IC bureau of mines information circular 8407

DUST CONTROL IN MINING, TUNNELING, AND QUARRYING IN THE UNITED STATES, 1961 THROUGH 1967

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

March 1969

DUST CONTROL IN MINING, TUNNELING, AND QUARRYING IN THE UNITED STATES, 1961 THROUGH 1967

By Floyd G. Anderson and Robert L. Beatty

* * * * * * * * * * * information circular 8407

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

U.S. BUREAU OF MINES,
John F. O'Leary, Director

This publication has been cataloged as follows:

Anderson, Floyd Gustoff

Dust control in mining, tunneling, and quarrying in the United States, 1961 through 1967, by Floyd G. Anderson and Robert L. Beatty. [Washington] U. S. Dept. of the Interior, Bureau of Mines [1969]

50 p. (U. S. Bureau of Mines. Information circular 8407)

Includes bibliography.

1. Mine dusts. 2. Dust—Removal. 3. Mine ventilation. I. Beatty, Robert L., jt. auth. II. Title. (Series)

TN23.U71 no. 8407 622.06173

U. S. Dept. of the Int. Library

CONTENTS

DUST CONTROL IN MINING, TUNNELING, AND QUARRYING IN THE UNITED STATES, 1961 THROUGH 1967

by

Floyd G. Anderson[1] and Robert L. Beatty[2]

ABSTRACT

This report reviews and summarizes information on prevention and suppression of dust in mining, tunneling, and quarrying published in the United States from 1961 through 1967. Unpublished pertinent data developed or assembled by the Bureau of Mines during this period also are included.

INTRODUCTION

Under the auspices of the International Labor Organization, member countries review their own information on prevention and suppression of dust in the mining, tunneling, and quarrying industries. Each country regularly submits a summary report to the International Labor Office, the secretariat designated to collect, assemble, and distribute the data in the form of an international report. Under this arrangement the United States has submitted six reports covering the calendar years 1953 through 1967.

The material reported for the years 1953 through 1960 has already been summarized in three Bureau Information Circulars (9-10, 151).[3] This publication summarizes the subject data for the years 1961 through 1967. The Bureau plans to issue more Information Circulars as material is developed for the International Labor Office reports.

PNEUMOCONIOSIS STATISTICS

Available statistics showed that over 27,000 claims for pneumoconiosis have been settled by Workmen's Compensation Agencies in 18 States since 1950 (186). The claims amounted to approximately $132 million. The data were accumulated from published reports of State compensating agencies, by correspondence with those agencies and with groups such as insurance companies,

---

[1]Mining engineer, Health Research.
[2]Chemist, Analytical Methods Research.
Both authors are with the Health and Safety Research and Testing Center, Bureau of Mines, Pittsburgh, Pa.
[3]Underlined numbers in parentheses refer to items in the list of references at the end of this report.

and in part by abstracting case files. It was stated that this is undoubtedly an underestimate of the true situation. The period covered for the 18 States ranged from 8 to 13 years. Data were not obtainable from 30 States having legal provisions for compensation of one or more of the pneumoconioses.

Awards made by the Social Security Administration from 1959 through 1962 (166) for total and permanent disability to men under age 65 were tabulated by occupation, age group, and disease. For miners and mining machine operators, one-third of the disabilities were due to pneumoconiosis of occupational origin, and one-ninth were due to emphysema. High proportions of these diseases were also found in other occupations which included significant numbers of underground workers.

A statistical study of the Vermont granite industry (16) shows that sustained and improved dust control has been accompanied by a remarkable reduction in the incidence of silicosis. The Vermont granite manufacturing industry employs about 1,700 men. More than 90 percent of these workers are X-rayed annually by the Vermont Department of Health. There has been no occurrence of silicosis in any person whose exposure has been limited to the 26 years since 1937 when industry-wide dust control procedures were started. If the prevalence rates of the precontrol period were applied to the present labor force, at least 146 cases of silicosis might be expected. The data in this report substantiates the use of the new formula of the American Conference of Governmental Industrial Hygienists (ACGIH) (5) for determining the threshold limit value for Vermont granite dust.

Additional pneumoconiosis statistics are included in the following section, Medical and Environmental Studies.

MEDICAL AND ENVIRONMENTAL STUDIES

Federal Government

Metal Mining

In 1961 the Bureau of Mines and Public Health Service completed a comprehensive joint medical-environmental survey in the metal mining industry (167). It was conducted to evaluate the magnitude of the industry's silicosis problem. The environmental study was conducted in 67 mines, including eight uranium mines, employing approximately 20,500 persons--14,000 of whom worked underground and 6,500 in surface operations. At the time of the study, this group represented more than 50 percent of the working population of underground metal mines in the United States. The medical study included employees from 50 of the 67 mines in the environmental study and additional uranium mines. The mines included in the joint study represented virtually all metals mined in commercially significant quantities in the United States and every principal mining method.

Medical examinations, including medical histories, occupational histories, and chest roentgenograms, were completed on a total of 14,076 currently employed metal mine workers. Of the 14,076 chest roentgenograms taken, 476 or

3.4 percent were classified as consistent with a diagnosis of silicosis. Of these, 305 were classified as simple silicosis, and 171 were classified as complicated silicosis. Although the overall prevalence rate for the study was 3.4 percent, it varied greatly, ranging from 12.9 percent in one mine to zero in seven mines.

Silicosis, for the most part, was confined to older miners with more than 15 years metal mining experience. Silicosis was not observed in the chest X-ray film of any miner under 35 years of age, and only seven cases, 0.4 percent, were found in the 35- to 39-year age group. Beginning with the 40-to 44-year age group, with a prevalence rate of 2.4 percent, there was a moderate increase in the rate with each succeeding age group which tended to level off at about 12 percent for men from 55 to 64 years of age. Of the 63 men examined who were 65 years of age or older, about one-third were silicotic.

The incidence of silicosis was related to years of work at the mines as follows: No cases occurred with less than 5 years of exposure. Seven cases, or 0.2 percent, occurred in workers with 5 to 9 years of exposure, and 58 cases occurred with 15 to 19 years of exposure. After 20 years of exposure, the prevalence rates rose rapidly: For 20 years exposure, 7.6 percent; for 25 years exposure, 12.1 percent; and for the four exposure groups working 30, 35, 40, and 45 years or more the prevalence rate averaged about 17 percent.

So far as possible, each employee was classified according to his principal occupation. However, all men who had spent 10 years or more at the working face of a mine were classified as faceworkers. Over one-half of all silicosis cases occurred among men classified as faceworkers. With 10 to 19 years of mining employment faceworkers showed a silicosis prevalence of 3 percent which rose to 19 percent among men working 20 years or longer. Smaller but significant silicosis ratios were also found among employees with more than 20 years employment in other underground operations, surface maintenance and construction work, and surface mill operations. Surface transportation and miscellaneous surface operations showed very few cases of silicosis, except among older men who previously spent many years underground.

There was little relationship between the size of a mine and the prevalence of silicosis. The prevalence of silicosis was slightly greater among employees with experience in two or more mines. There was no great difference in the pattern of silicosis prevalence which could be attributed to a difference in the metal that was produced.

A 1939 study (167, p. 31) of nonferrous metal mine workers in Utah presented data which could be contrasted with data from a group of 12 western lead-zinc mines investigated during the 1958-61 study. The overall prevalence of silicosis was found to be 40 percent lower than in the earlier study. Even more striking were the reductions in the silicosis rate of 80 percent among persons employed in the mines less than 10 years and of 73 percent among those employed 10 to 19 years.

A special study was made of the records of a group of metal mine workers from an iron ore mine which has had a silicosis control program underway

continuously since 1933. Among the 1,293 men included in the records, 410 had worked in the mine before 1933 and, thus, had been exposed before the improvement in the mine environment. Silicosis was found in 83 of the men at the time of the first X-ray examinations in 1933, and 16 of them whose X-rays were negative in 1933 later developed silicosis. There has not been a single case of silicosis among the 883 men who were employed after the control program began in 1933. Many of these men have been exposed to the mine environment for more than 20 years.

In the environmental phase of the joint-silicosis study particular emphasis was placed on evaluation of airborne dust in mine working areas. Observations were also made of pertinent factors such as dust control methods, ventilation, working methods, and air quality.

A total of 14,837 midget impinger samples of airborne dust and 234 samples of settled dust were obtained underground for evaluating dust exposures. From these samples, 789 full-shift, weighted average exposures were determined for specific underground operations. Of the weighted averages 13.2 percent were above the 1967 ACGIH threshold limit values (5). Particle-size characteristics of the airborne dust were determined from 481 membrane filter samples by optical microscopy. All determinations indicated significant numbers of particles in the range of sizes capable of retention in the alveolar spaces of the lungs.

Dust concentrations obtained at a group of lead-zinc mines in the Western States were compared with dust concentrations obtained in the 1939 study of Utah lead-zinc mines. A very substantial improvement in dust control during the intervening years was indicated. Dust concentrations for comparable occupations underground have been reduced at least 80 percent and, in some instances, as much as 90 percent.

The joint study (167) was designed to determine the prevalence of silicosis among the work force of the industry, to define present-day environmental conditions, and to seek answers to the following questions:

1. Are the cases presently occurring the result of precontrol exposure, in view of the long latent period for the development of silicosis?

2. Are they the result of failure to apply dust controls universally?

3. Are cases occurring because the standards for acceptable levels of dustiness in use since 1935 are inadequate?

With respect to these questions and to other facets of the problem, the following conclusions were drawn:

1. Considerable progress has been made in the metal mining industry in the prevention of silicosis. The present overall prevalence rate of 3.4 percent is substantially lower than the rates encountered in previous surveys. The range varied among individual mines, however, from 0 to 12.9 percent and shows the prevalence of silicosis is not uniformly distributed throughout the industry.

2. The industry has instituted or improved many dust monitoring and dust control systems during the past 25 years; this has resulted in marked reductions in dust exposures. Since the development of silicosis requires a considerable period of exposure, the full benefits of these improved environmental working conditions cannot be fully evaluated at this time.

3. There was a substantially higher prevalence of silicosis among men who worked in mining at some time before 1935 than among men who have worked the same number of years since 1935. Two hundred and ninety-eight cases of silicosis were found in workers who began work in mining prior to 1935. One hundred and twenty-eight cases of silicosis were found among men exposed only since 1935.

4. The occurrence of silicosis due to exposure after 1935 and the excessive dust exposures found in some of the mines studied, provides evidence that effective dust control has not been universally practiced.

5. Data obtained in the study do not permit judgment of the adequacy of present standards. In most of the mines studied, the environmental data needed to define working conditions from 1935 to the time of this study were lacking.

6. Combined medical and environmental surveillance and control can prevent the development of clinically significant silicosis among miners.

7. With regard to specific environmental situations the following can be concluded:

a. In many instances, ventilating currents in the working areas were not being used to best advantage. Recirculation of air particularly posed a problem, and airborne dust was often carried from one working place to another.

b. Drilling, slushing, and mucking were the most prolific dust-producing operations to which men at the face were exposed. Workmen engaged in haulage and crusher operations were also exposed, in several instances, to excessive concentrations of dust.

c. Water applied to the muck piles assisted materially in reducing dust concentrations during subsequent operations.

d. Dust concentrations in shops and mills, except during cleanup operations, presented no particular problems.

e. The need for better maintenance and cleanup practices around crusher installations was indicated.

f. Concentrate loading and cement mixing were sources of excessive concentrations of dust; however, very few workmen were engaged in such operations.

8. This study has provided extensive, basic data on the current prevalence and characteristics of silicosis among employed metal miners and on the magnitude and nature of current dust exposures in the metal mining industry. It represents an important baseline for continued studies. In view of the long latent period before the development of silicosis, further comprehensive medical and environmental studies over a period of years will be necessary to develop additional essential information on the problem. This will include determining if new cases of silicosis are occurring or known cases are progressing, their relationship to occupational dust exposures, the need for improved or additional dust control measures, and the adequacy of present standards for evaluating siliceous dust exposures.

A summary of environmental and medical findings relating to health hazards in uranium mining and milling was reported by the U.S. Public Health Service (13). Environmental surveys showed many mines with concentrations of radon-daughter products above a recommended working level of 1.3×10^5 mev of potential alpha energy per liter of air. Preliminary calculations applied to miners with 3 years or more of uranium mining experience showed that five lung cancer deaths have occurred where 1.1 were expected. The radiation exposure of uranium miners was the subject of public hearings (188) initiated by the Joint Committee on Atomic Energy. The record of those hearings constitutes the most comprehensive collection of information ever amassed concerning the exposure of human beings to radiation incident to the mining of uranium. The information was commended to study by Congress and other responsible officials for guidance in establishing standards and operating procedures relative to radiation protection.

Coal Mining

The Public Health Service conducted a medical survey of almost 4,000 bituminous coal miners and former coal miners of the Appalachian Area (31, 68). The study revealed the presence of a job-related chest disease, coal workers' pneumoconiosis. About 10 percent of the currently employed miners in the area showed X-ray evidence of pneumoconiosis; roughly 20 percent of the formerly employed miners in the area gave similar indications. Evidence that years of exposure to coal dust is a factor in the disease can be seen in the following table:

Years underground	Percent with pneumoconiosis	
	Currently employed	Formerly employed
0- 9	2.0	1.9
10-19	4.0	6.2
20-29	8.6	21.3
30-39	20.6	21.4
40 and over	24.2	23.0
Average	9.6	18.6

To check the possibility that general living and environmental conditions or other nonoccupational factors might be responsible for chest diseases, the study included medical examinations of miners and nonmine workers living in the

same community. X-ray evidence of pneumoconiosis was found in 15 percent of the coal miners and in less than 1 percent of the nonmining group.

Another significant part of the survey of coal workers' pneumoconiosis was a statistical study of death rates for U.S. coal miners (75). Based on records for the year 1950, the death rate for coal miners was about twice that of the general working male population, and death rates for diseases of the respiratory system were about five times that for the general working male population.

Extensive data on dust concentrations in the mines will be necessary to provide the positive link between dust and disease, and the key to prevention (31). A joint committee of the Division of Occupational Health of the Public Health Service and the Bureau of Mines is at work planning an environmental survey in bituminous coal mines. Members of the industry, including representatives of mine operators, mining associations, and the United Mine Workers of America are serving this committee in an advisory capacity (101, 193). The Bureau is conducting laboratory and field investigations to determine the effectiveness of the instruments and techniques to be used for sampling and evaluating airborne dusts during the survey (40, 68, 198).

State Government

Because the extent of the pneumoconiosis problem in the Pennsylvania bituminous coal industry was not known, the Division of Occupational Health, Pennsylvania Department of Health, embarked on medical and environmental studies in 1959 (115-116, 124) to define the problem. The medical study consisted of obtaining occupational and medical histories, vital capacity determinations, and chest roentgenograms. These data were obtained by the examination, on a voluntary basis, of approximately 16,000 working and retired bituminous coal miners. From the study it was learned that approximately 14 percent of western Pennsylvania and 34 percent of central Pennsylvania miners had roentgenographic evidence of pneumoconiosis. As expected, the prevalence of pneumoconiosis increased with age and length of exposure. No correlation was found between subjective symptomatology and roentgenographic diagnosis. On the basis of the work done, it was concluded that Pennsylvania has a pneumoconiosis problem of greater magnitude in its bituminous mining population than was previously believed.

The medical study was extended to include the anthracite industry (125), and data were obtained by examination of 1,430 working and 428 retired anthracite miners. It was shown that incidence of pneumoconiosis increased with age and years of exposure for both working and retired anthracite miners. Approximately 30 percent of the working miners and 75 percent of the retired miners had or were suspected of having pneumoconiosis in some stage of development. Of the working men with less than 20 years of work in the mines, 90 percent had no roentgenographic evidence of pneumoconiosis compared with 50 percent in those with more than 40 years in the mines. Only 20 percent of the retired miners with 40 or more years in the mines were found to be without evidence of pneumoconiosis.

The environmental study was begun by the Division of Occupational Health, which completed a two-year study of dust conditions in Pennsylvania mines (18-20). Dust surveys were conducted in 24 anthracite and 14 bituminous coal mines. More than 1,400 samples of dust were collected for determination of number concentration, free silica content, and particle-size distribution. In general, more airborne dust with greater free silica content and smaller particle size was found in anthracite mines than was found in bituminous coal mines.

Since 1960 the Pennsylvania Department of Mines and Mineral Industries has assumed responsibility for the environmental phase of a continuing pneumoconiosis activity (61, 92). The Division of Occupational Health has retained responsibility for the medical phase and the compilation of statistics (202). Periodic surveys are conducted by dust investigators who report results to both departments. Mine inspectors are informed of hazardous dust conditions, and they contact mine management for correction (28, 66, 100).

The results of the pneumoconiosis studies conducted by the Pennsylvania Departments of Health and Mines and Mineral Industries, and the rising cost of compensation (108, 113-114) for pneumoconiosis among coal miners caused Pennsylvania's Governor, William W. Scranton, to call a conference on pneumoconiosis (159). The purpose of the conference was to review the pneumoconiosis problem of Pennsylvania coal miners and to consider and propose recommendations for prevention, diagnosis, and compensation of the disease. One session of the conference was devoted to the subject of dust control. Presentations included discussion of the Commonwealth's regulatory and research activities, evaluation of dust exposures, dust control practices in use in bituminous and anthracite mines, and research projects being conducted by other government agencies and by equipment manufacturers.

DUST PREVENTION AND SUPPRESSION PRACTICES

Control Programs

A dust control program resulting in a desirable environment for copper-mine workers was described (109). The program stresses the importance of positive ventilation in working areas for dilution of airborne dust to acceptable concentrations, the use of water for suppressing dust generation, and the use of company-designed dust collection equipment to clean contaminated air for reuse. Compressed-air-and-water blasts are used in all sill headings to minimize dust dispersion during and after blasting and to wet the muck piles uniformly.

The summary report (165) of a meeting of the Governors of uranium producing States and their representatives concludes that mounting evidence points to the existence of severe health hazards in uranium mines. The assistance available from Federal agencies and the objectives of State authorities seeking solutions of these serious health problems are outlined. A company program for control of radiation exposure in its underground uranium mines in Colorado is described (23-24). The program includes the determination of exposures by a field method developed by the U.S. Public Health Service and

the annual physical examination of workmen, supplemented by medical studies in cooperation with the Public Health Service. Proper ventilation is emphasized as mandatory for adequate control of dust and radiation exposures.

Recommendations generally applicable to the nation's underground metal mining industry and related to dust prevention and suppression programs were outlined as follows in the report of the environmental and medical study conducted by the Bureau of Mines and U.S. Public Health Service (167):

"1. Each mining company should maintain a dust monitoring program conducted or supervised by a person competent in the techniques of dust sampling and interpretation of results.

a. For determining levels of exposure, dust samples should be taken in the breathing zones of workmen.

b. The program should be conducted in such a manner that it will detect changes in environmental conditions and promptly locate conditions in need of correction.

c. Accurate and complete records of dust conditions should be kept. These should be tabulated, analyzed, and reported to a responsible level of management at regular intervals.

"2. Proper methods of dust control should be initiated promptly when the need is discovered.

a. Adequate ventilation by mechanical means should be provided at all working places.

b. Recirculation of air should be held to a minimum consistent with good mining practice.

c. All ore and broken rock should be thoroughly wetted to reduce dust during subsequent handling operations.

d. All dust control devices and materials handling equipment, both underground and surface, should be frequently inspected and maintained in proper working conditions to limit to the lowest practicable level the generation or dispersion of dust.

e. Men should not be permitted to reenter a workplace after blasting until sufficient time has elapsed for dust and gases to be reduced to a safe level.

"3. Workers should be informed of the dust hazards associated with their job, the methods employed for the control of dust exposure, and instructed in good work procedures to minimize dust dispersion and in the proper use of equipment. All employees should give their full cooperation in helping to maintain an effective dust control program.

"4. Mining companies should request, whenever necessary, the assistance of the Bureau of Mines or other qualified agencies in instituting and evaluating dust monitoring and dust control programs."

Water and Wetting Agents

As noted in most of the articles on dust control referenced in this report, water is a most important and convenient agent for suppressing dust (155, 172). Although not used to any great extent in underground mining, wetting agents can increase the effectiveness of water.

There were few reports of wetting agents being used in coal mines and these reports dealt with the control of dust generated by continuous mining machines, which continues to be a problem. A noticeable reduction in visible airborne dust in face areas resulted from adding a wetting agent to the spray water supplied to machines mining the low volatile coal of the Pocahontas seam (80). The same company found wetting agents ineffective when mining the high volatile coal of the Pittsburgh seam. The ineffectiveness of a wetting agent applied for control of Pittsburgh seam coal dust was verified by a second company (111). It was noted in a Bureau of Mines study (11) that the use of wetting agents reduced the dust loading of return air by about 30 percent compared with the use of water alone.

Surface-active agents are used to a greater extent in surface operations such as tipples, coal preparation plants, and loading facilities. A powerplant coal-dust problem (163) at a truck-hopper house designed for the unloading of trucks and railroad cars simultaneously was solved by installing sprays around the top of the hoppers, over the railroad cars, and at the hopper-to-main conveyor discharge point and by adding a surface-active agent to the spray water. Because the wetting agent caused the water to wet the coal more completely, dust was eliminated at three other transfer points in the conveying system. The use of less than 0.5 percent moisture, by weight, suppressed gypsum-rock dust at quarries and plants when a surface-active agent was added to the water (170). Control of dust by use of water with a surface-active agent was described for a railroad car-to-lake freighter loading operation, a self-unloading lake freighter dust control system, and a dock crane unloading operation. The cost of chemical treatment was estimated to be between 0.35 and 1 cent per ton of sprayed material.

Though not practical for underground use, steam has been used for a number of years to alleviate dust at transfer points of conveyors in tipples and preparation plants of one coal mining company (80). The effectiveness of dust suppression by steam is attributed to the reduced surface tension of hot water.

Emulsified asphalt has proven to be a more effective agent than lignin sulphate for reducing dust on haul roads at several open pit operations in the southwestern part of the United States (90).

Roof Control

Roof bolting has been so widely accepted that the bituminous coal industry now considers it to be the standard method of roof support (74). The Bureau of Mines estimated that approximately 60 percent of the total underground production of coal for the year 1966 was mined under bolted roof and reported the installation of approximately 50 million bolts (39). The development of successful drilling and dust-collecting equipment for bolt hole drilling of coal mine roof is discussed in the next section under drilling. A special editorial feature (97-99) for coal operators summed up the theory and practice of coal mine roof support and discussed the need for ventilation and dust control.

Industry has also found rock bolts advantageous for supporting ground in metal mines (197) and tunnels (168); however, the extent of such use is not known. In metal mines and tunnels adoption of bolting poses no new dust problem as conventional drilling equipment is used for installation.

Drilling and Blasting

Most of the problems associated with the development of drilling and dust control equipment for roof drilling in coal mines have been resolved (74, 101). Highly satisfactory rotary and rotary percussion roof bolting machines have been developed for drilling coal mine roof. Some hard roofs require the use of pneumatic percussion drills. The rotary or pneumatic percussion drills most commonly used have integral dust-collecting systems which feature collection of the drill cuttings through the drill steel. During the period covered by this report much effort was expended in improving the design of drill steel and bits for through-steel dust collection (81). By the end of 1967, 160 certificates had been issued by the Bureau of Mines approving equipment for use in connection with rock drilling in coal mines (8, 110).

In general, coal drills are not equipped with arrangements for dust control. Suppression of the drill dust has been accomplished by use of a swivel and hollow augers for introduction of water into the drill hole (154). It is believed that eventually coal drills will be built with integral dust-collecting systems similar to those used on roof-bolting drills.

The development of heavier drilling equipment mounted on mechanically controlled jumbos has advanced the practice of longhole drilling for drifting, stoping, and raising in metal mines (84). Longhole drilling eases the dust control problem, because less hole collaring is required, dust generation decreases with the depth of the hole, and ventilation requirements are less critical. Drilling of the blastholes from surface during construction of a coal mine ventilation shaft 230 feet deep, was described in a recent report (180). After drilling was completed, blasting progressed from bottom to top in 12-foot stages.

A method of suppressing dust from dry percussion drilling in quarries, construction sites, and open pit mines was developed and has gained wide acceptance (64, 123, 135). Water with an added wetting agent is introduced

into the air used for flushing the drill cuttings from the hole. Dilution ratios range from 800 to 3,000 parts of water to one part of surfactant. The amount of water required is considerably less than for wet drilling and is dependent upon the size of the hole being drilled, the drilling rate, and the type of material being drilled. The proper amount of solution, about 7 gallons per hour for a 3-1/2-inch-diameter hole, causes the drill cuttings to be blown from the hole as damp dust-free pellets. It was reported that the method has been used successfully underground and that its use may grow, especially where water is in short supply.

In conventional mining of coal, water-filled plastic bags came into use for stemming blastholes. Their use in conjunction with an air-and-water blast results in a considerable reduction of the dust from blasting (193).

Extraction of Material

Continuous Mining of Coal

The use of continuous-mining machines continued to increase. In 1965, 142 million tons of bituminous coal, representing 43 percent of underground production, was produced in 447 mines using continuous-mining machines, and in 275 of these mines continuous-mining machines were used exclusively (201). Much effort was directed toward the solution of the dust problems created by these machines due to their high production rates. Only partial success was realized. Dust suppression investigations were directed toward the reduction of dust at the face by the use of foam; the direction of water to the cutting edge of the bit; the study of water spray nozzle design, operating pressure, and placement; and the cutting-bit design. To prevent excessive dust exposures of mining crews, ventilation was arranged so as to direct fresh air over the machine and dust-laden air into the return airways. To minimize the explosion hazard of settled dust in the return airways, "trickle dusting" was developed.

The Bureau of Mines, working cooperatively with mining companies, investigated the possibility of confining the dust generated by ripper and boring-type machines under a blanket of foam to prevent its becoming airborne (111). Results were promising, but foam generation at higher expansion rates must be realized before the value of the method can be appraised. Directing spray water to the cutting edge of the bits on the arms of a boring-type miner reduced dust generation significantly. The respirable dust at the machine operator's breathing zone was reduced 78 percent from that observed in baseline measurements (80). Success of the effort led to directing water to the bits on the cutting wheels of ripper-type machines. It was determined that water spray nozzles suppress dust most effectively when operated at pressures ranging from 200 to 300 psi (80, 111). It is common practice to equip machines with full cone spray nozzles for delivery of 5 to 15 gallons of water per minute. The dust from a boring machine was alleviated when supplied with 25 gallons of spray water per minute (142). A self-sharpening, plumb-bob-shaped, tungsten-carbide-tipped cutting bit was developed (126). An advantage claimed for the bit was less dust at the face due to the production of coarse cuttings (74). Ventilation procedures and rock-dusting techniques used for

minimizing dust problems created by these machines are discussed under the headings deposited dust and ventilation.

Longwall Mining of Coal

The growth of longwall mining in the United States was outlined, and a bright future was predicted in a recent publication (47). The first longwall face in a coal mine was established on an experimental basis in a southern West Virginia mine in 1951 (85). After 2 years experimentation, the longwall system was adopted on a production basis, and production has continued to the present time. Other companies have found it to their advantage to adopt the system, and in 1965 about 1.6 million tons of coal were produced from 13 longwall faces being operated in coal mines in four States (179, 201). Ease of ventilating the longwall face for rapid removal of dust and methane gas is an advantage claimed for this method. The development of a water-infusion technique was required in order to solve the dust problem at a longwall face in a southern West Virginia mine (141). Drenching the face area with water by spraying did not suppress the dust raised by the coal planer or by the billowing action of falling roof rock. However, the infusion system has resulted in significant suppression of the dust and has made the coal more planable. Infusion holes 6 inches in diameter, 200 feet deep, and spaced at 200-foot intervals are drilled in the head entry of the longwall panel in advance of and parallel to the face. Water with a wetting agent added is pumped into the holes at a pressure of 600 pounds per square inch and at a rate of 15 gallons per minute. About 10 gallons of infusion water are used per ton of coal produced. The holes are drilled above a shale binder which lies 12 to 18 inches below the top of the coal seam. Water travels through the coal above the binder to the face region where the binder, broken by ground pressure, allows the water to enter the bottom coal.

Hydraulic Mining of Coal

A Bureau of Mines hydraulic coal mining research program was outlined (33, 195-196), and research results were summed up in a progress report (153). Five field trials of coal extraction by hydraulic mining were described: One in the flatlying Pittsburgh coalbed near West Lebanon, Pa., where the coal was mined and loaded simultaneously by mounting the hydraulic monitor on a conventional loading machine; one in a 13-foot-thick pitching anthracite coalbed where chambers and crosscuts were mined with a specially designed hydraulic mining machine (32); two in the 42° pitching No. 5 coalbed at Roslyn, Wash., where a self-advancing hydraulic roof support system was used for a monitor mounting in development work and pillars were mined using a hand-held monitor (147); and one in the 26° pitching "A" coalbed near Carbondale, Colo., where a post-mounted hydraulic monitor was used to drive raises and crosscuts. It was concluded that this novel method of mining is particularly advantageous for mining pitching coalbeds not amenable to mining with conventional mechanical equipment. The full potential of this extraction method can be realized only when it is made part of an integrated system including roof control, hydraulic transport and hoisting of the coal, and other auxiliary operations.

The adoption of commercial hydraulic mining of bituminous coal has been announced (50, 127). With regard to dust control in hydraulic mining operations, airborne dust at the faces and in the air courses is reduced significantly, and dust is not blown off the top of loaded cars, eliminating the need for costly cleanup and heavy rock dusting of haulageways.

Water Infusion

Infusion of the coalbed with water was one of several methods investigated by the Bureau of Mines for draining methane from strata in advance of mining the coal. In the first study (132-133) it was observed that water infusion tended to reduce the amount of dust at the face when the coal was mined. The second study (134) included investigation of the affect of dust suppression by the water-infusion method. Dust exposures of crew members and dust loadings of return air from the working face were determined for continuous-mining operations before and after water infusion of the coalbed. In a Bureau of Mines internal report (42) the following was concluded:

1. Dust generation of the mining operation was reduced by infusion of the coalbed. The reduction rate could not be determined accurately during this study, but does not appear to be great enough to justify infusion solely for control of dust generation.

2. No advantage was demonstrated for the use of a wetting agent with the infusion water.

3. Dust suppression was adversely affected when mining of the infused coal was delayed.

4. High dust loading of the return air resulted when more than 9,200 cfm of air was used for face ventilation.

5. Satisfactory mining-crew dust exposures resulted when 5,600 cfm or more of air was used for face ventilation, 9 gpm or more of spray water was used to allay dust, and the coalbed was infused within 48 hours of mining.

Loading, Transport, and Unloading of Mineral and Dead Rock

Control of coal dust during hand or mechanical loading is accomplished by wetting the coal. The sprays are either hand-held or mounted on the loading machines. When a dry coal-cleaning process restricts the amount of water that can be used at the coal face, wetting agents are sometimes added to the water to increase its effectiveness. At transfer and unloading points of transport systems, properly installed water sprays are used successfully. Experimental use of a high-expansion foaming agent reduced dust counts at belt-conveyor transfer points by 50 percent (112). The superior performance of the foaming agent compared with "water alone" was not great enough to justify the added expense of adopting the system. Coal is not crushed underground, as a general rule; however, at one such unique operation (48), coal-dust control was accomplished by installation of an efficient dust-collection system.

Deposited Dust

Sprinkling with water or salt solutions is usually resorted to for consolidation of material deposited on roadways. At one metal mine where water gave only temporary relief, roadways are sprinkled with a water-soluble asphaltic material (184). Treatment consists of Bitumate,[4] mixed with water to make a 5-percent solution, sprayed from a tank car on a 2- to 4-week schedule.

The Bureau of Mines continued the study of float-coal transport, deposition, explosion hazard, and control methods (144-146). Initial studies on float-coal transport and deposition indicated the following:

1. The air velocity has a marked effect on the quantity of dust deposited on the floor at a given station and consequently on the quantity in suspension.

2. For a given air velocity, the quantities of dust deposited per unit area and maintained in suspension at a station vary inversely as the square root of the distance from the dust source.

3. For a given air velocity, the quantity of dust deposited at a station is directly proportionate to the quantity of dust dispersed. Deposition at a station was not affected by the rate of dust dispersion in the 0.3 to 2 lb/min discharge range.

4. Dust deposition is relatively uniform across the width of entry.

5. The quantity deposited on rib-roof surfaces is a small proportion of the total dust dispersed. Dust deposition on trays decreases approximately linearly with height above the floor.

6. The quantity of dust deposited is affected by the shape of the trays. Dust deposition on trays having a 1/4-inch-circumferential lip may be 20 times more than on flat trays when the air velocity is 550 fpm. At an air velocity of 200 fpm, three times more dust was collected than on flat trays. About the same quantity of dust was deposited on glass and plastic sheets as on a flat galvanized sheet-metal surface.

7. The relative humidity (50 to 94 percent) does not affect dust deposition.

To determine the quantity of float coal deposited in return airways and belt entries, the Bureau surveyed 50 mines located in the major coalfields of the United States (105). The mean quantity of deposited dust was found to be 0.02 oz/cu ft of entry volume, of which 73 percent was on the floor and 27 percent was on the ribs and roof. The float coal concentration was more than 0.1 oz/cu ft in 6 percent of the dust samples. Statistical analysis of the samples indicated that the quantity of float coal does not differ significantly between samples collected from mines using conventional or continuous mining equipment, between mines working in coal seams having a low or high

---

[4] Reference to specific brands is made for identification only and does not imply endorsement by the Bureau of Mines.

volatile ratio, located in Eastern or Western States, or producing less than or more than 5,000 tons of coal per day. Similarly, no significant difference was observed between samples from entries having a low or a high velocity air current and from locations adjacent to or distant from the last open crosscut.

Bureau recommendations (146) for alleviating the float coal hazard included (1) using water sprays on mining equipment, (2) using rock dust to maintain a minimum of 80 percent incombustible in the top 1/8-inch layer of dust where float coal is deposited in amounts less than 0.1 oz/cu ft, (3) mixing of the coal and rock dusts on the floor to insure 80 percent incombustible on the floor, if incombustible content of rib-roof surfaces is 80 percent or higher, and (4) dispersing rock dust into the return-air ventilating current during mining operations. Inert-dust dispersers and water jets activated by an explosion are being investigated for supplementing generalized rock dusting.

The handling of rock dust in bulk with newly developed equipment, was advanced as a means for drastically reducing the cost of rock dusting in multishift coal mines (3, 49, 52). Adoption of a bulk handling system at one mine (46, 55) resulted in the saving of $7.40 per ton of rock dust applied and increased mine safety.

Successful use of rock-dust dispensers on auxiliary fans was first reported in 1963 (69) for minimizing hazards which may result from layer deposition of coal dust in return airways (138). Rock dust was fed at a rate of 1/2 to 1 pound per minute into the discharge of an auxiliary exhaust fan ventilating the face of a continuous-miner operation. Dust samples were collected from the floor, roof, and ribs of the return airway at intervals of about 100 feet for a distance of 1,140 feet from the face. The floor samples had incombustible contents ranging from 82.8 to 85.5 percent. The composites of floor, roof, and rib samples had incombustible contents ranging from 65.6 to 90.4. The cumulative samples for 1,140 feet outby the face were homogeneous mixtures having incombustible contents of at least 78.7 percent. Others (14, 29, 67) have reported similar success. This practice has become standard operating procedure, and is now referred to as "trickle dusting" (71, 74).

Ventilation

Higher production rates and the mining of coal under deeper cover have increased methane and dust liberation in the mines and consequently the need for greater quantities of fresh air. The circulation of 5 to 10 tons of air for each ton of coal produced is not unusual (22, 53) and it is common to have 20,000 or more cfm of air in the last breakthrough within a distance of less than 200 feet from the face (86). Due to leakage, ventilation air losses in operating mines often amount to 70 percent of the induced airflow. The use of a material consisting of an industrial nylon laminated with vinyl was suggested for use in construction of temporary stoppings and line curtains (43). The construction of stoppings with polyurethane foam was also suggested (104). Reduced construction costs and air-leakage losses are advantages claimed for these materials. In a coal mine ventilation guide (51), fundamentals of mine ventilation were reviewed, industry's emphasis on improving ventilation at the immediate face was noted, and the use of the new materials and equipment now available was stressed.

Face ventilation is accomplished with line brattices or auxiliary fans supplemented by diffusion fans when required for the control of methane. Line brattice is used except when bulky face equipment prevents its proper installation. The efficiency of line brattice systems is dependent upon direction of airflow, method of installation, porosity of fabric, and tight-rib area (62-63). Successful ventilation of faces with line brattices where ripper-type continuous miners are used was described (22). When line brattices of jute material are installed properly 3,000 to 6,000 cubic feet of air per minute are provided to the faces. The intake air is directed over the mining equipment so that the mining crews are not exposed to the coal dust in the return air. If more air is required for methane dilution and removal, the regular jute curtain is backed with plastic material to reduce leakage through the line brattice. The installation of small diffusing fans and air ducts on Jeffrey Colmols for control of methane at faces where line brattice is used was reported (185). The line brattice can be hung on either side of the work place as the ducting allows air to be directed across the face in either direction.

Coal faces being advanced by full face boring machines are ventilated most successfully with auxiliary fans. A permit for the use of auxiliary fans must be obtained from the Joint Industry Safety Committee (118). A study of methods for ventilating continuous-miner places was made by the Bureau of Mines (175); the following recommendations were made concerning the use of auxiliary fans:

1. Each auxiliary fan should be of the permissible type and maintained in a permissible condition.

2. Each auxiliary fan should be installed and operated so that recirculation is avoided.

   a. Blowing-type fans should be installed on the intake side of the breakthrough.

   b. Exhausting-type fans should be installed on the return side of the entry or breakthrough.

   c. In all cases the quantity of intake air available to the auxiliary fan should be greater than the rated capacity of the fan.

3. Auxiliary fans should be operated continuously during face operations. If the auxiliary fan fails or is stopped, power to the face equipment should be disconnected until the fan is again in operation. During such stoppage, face ventilation should be maintained by conducting the primary air current into the place in such a manner that accumulations of methane are prevented.

4. Auxiliary fans should not be operated during the interruption of the main ventilating current. Any accumulation of methane resulting from such interruption should be removed by conducting the air current into the place with line brattice after the restoration of the main ventilating current and before auxiliary ventilation is resumed.

5. In places where auxiliary fans are used, the ventilation during scheduled idle periods (that is, weekends, idle shifts, etc.) should be by means of the primary air currents conducted into the place in such manner that the accumulation of methane is prevented.

6. When auxiliary systems incorporate a small blower or diffuser mounted on the machine, such blower or diffuser should be stopped immediately if the auxiliary fan or primary air source fails. This will prevent the recirculation of air-gas mixtures at the face.

7. If it is necessary to prevent intermittent operation or operation below capacity, the auxiliary fan should be installed on a separate power source.

8. The size of the fan and tubing should be adequate to provide the necessary air volume requirements when using the maximum length of tubing or duct that may be necessary.

9. Ducts or tubing should be installed and maintained to prevent excessive leakage and should be suspended from the roof or timbers.

10. Machine-mounted auxiliary fans or diffusers should be mounted and maintained so that accumulations of coal or debris do not obstruct the passage of air through the fan or ducting.

11. The installation and operation of the auxiliary units should be supervised and controlled by a competent person responsible to the mine foreman.

A hydraulically driven exhaust fan was mounted on a full face boring-type continuous miner to exhaust air from the face (30). Mine personnel believe it provides the best face ventilation for that type of boring miner. Over 5,000 cubic feet of air per minute are discharged from the face into the return at the end of 170 feet of 18-inch tubing. It was claimed that the arrangement provides a movement of fresh air over the mining machine, good face visibility, and better ventilation for methane control at the immediate face. Testing and use of auxiliary fans supplemented by diffusion fans for satisfactory ventilation of boring-type miner faces has also been described (70, 156). At one operation, depending upon methane liberation, up to three auxiliary fans are used to exhaust air from the face through 16-inch noncollapsible tubing. The fans are driven by 5 hp electric motors and deliver 4,000 to 5,000 cfm of air at the end of the tubing. If more than one fan is used, one ventilation line is ended at the coal pile at the end of the boom of the continuous miner. The auxiliary exhaust fans were fitted with 200-pound rock dust hoppers for trickle dusting. A small diffuser fan, mounted on the continuous miner, is always used in conjunction with the auxiliary exhaust fan, to provide air movement in the corner of the face opposite to the ventilation tubing.

To assure positive ventilation at the faces of boring machine operations, the Bureau of Mines has included the following condition in its proposed revision of Schedule 2 (38) under which electric motor-driven mine equipment and accessories are certified for use in gassy coal mines:

§ 18.22 Boring-type machines equipped for auxiliary face ventilation.

Each boring-type continuous-mining machine that is submitted for approval shall be constructed with an unobstructed continuous space(s) of not less than 200 square inches total cross-sectional area on or within the machine to which flexible tubing may be attached to facilitate auxiliary face ventilation.

The Bureau of Mines conducted a study of dust control in connection with continuous mining of coal(11). The effectiveness of dust suppression methods being employed was evaluated for the purpose of establishing operating procedure guides for adequate dust control. Thirty-eight mining machines, operating in 15 mines, were observed. The mines that were visited were working in nine different coal seams and were using five different types of mining machines. Blowing and exhausting line brattices or auxiliary fans, operating exhausting, were used for face ventilation. At all mining operations observed water was being used for allaying dust, and at two mines a wetting agent was being added to the water. Following is a summary of what the investigation revealed regarding conditions for dust exposure control:

1. Air unpolluted with dust should be directed over all the men of the mining crew. Here, air unpolluted with dust means air having a dust concentration of 5 million particles per cubic foot, or less.

2. Joy Continuous Miner operations need a minimum of 2,500 cfm of air for face ventilation and about 10 gpm of water for allaying dust, or 4,000 cfm of air and 5 gpm of water. If the machine is equipped with roof drills or timbering is concurrent with the machine operation, a minimum of 4,000 cfm of air and 10 gpm of water is needed.

3. Lee Norse Miner operations need 3,500 cfm of air for face ventilation and about 10 gpm of water for allaying the dust. When less than 10 gpm of water are used, a minimum of 5,000 cfm of air is needed.

4. Judging from limited data, the requirements for Jeffrey Colmol operations are comparable to those for Lee Norse Miner operations.

5. Men installing roof supports or extending line brattice or ventilation tubing should wear respirators when working in return air. Return air, here, means air that has left the face after passing over the mining machine.

The first condition for control indicates that the face should be ventilated by an exhaust system. This can be accomplished either by exhausting the air behind line brattice or with an auxiliary fan through noncollapsible tubing. An exhaust system may be used safely for ventilating gassy mine faces if the system provides for diffusion of the gases at the face and has sufficient capacity. The Bureau of Mines studied this problem and outlined safe procedures (175). Dust loadings of the return from the face of each

operation observed were measured and ranged from 0.05 to 26.7 pounds of coal dust per hour of continuous operation. The effectiveness of the use of 5 gpm of spray water was demonstrated in one instance by dust loadings of 2.5 pounds per hour with water to the machine spray nozzles turned off and 0.4 pound per hour with water turned on. The effect of adding a wetting agent to the spray water was demonstrated by dust loadings of 1.4 pounds per hour when water alone was used and 1.0 pound per hour when a wetting agent was added to the water to make a 1-percent and a 2-percent solution. The effect of a wetting agent was demonstrated in a second instance by dust loadings of 4.5 and 4.3 pounds per hour when water was used, and by loadings of 2.9 and 3.0 pounds per hour when water with a wetting agent added was used

The state of the art of face ventilation was summed up (122) as follows:

1. Normally we have sufficient air available, at the last "open crosscuts."

2. We can, within limits, control the air available, but more applied research should be done on better checks or doors.

3. Using the proper material in well-installed brattices, we can move sufficient air to the face where conventional equipment is operated.

4. In the case of continuous miners or other bulky machines, additional research on clearing the face of explosive concentrations of methane is needed.

5. Research is needed to reduce friction sparking by the bits of machines.

6. Additional work should be conducted to reduce the dust produced and to allay whatever dust is evolved.

Personal Protective Equipment

A cryogenic breathing apparatus for continuous-miner operators, an innovation in environmental dust control, was tested and evaluated by one coal mine operator (80). The prototype consisted of a portable cryogenic storage vessel and heat exchanger mounted on the continuous miner, and a breathing mask for the operator with a demand-type regulator and a gas delivery hose having a quick-disconnect coupling. An improved version of the prototype combined the vessel, heat exchanger, and auxiliaries into one compact unit for mounting on the continuous-mining machine. Other methods of providing dust-free air at comfortable temperatures to the machine operator, such as the use of low-pressure compressors, were being investigated also. In view of the known limitations to the use of respirators (176), these efforts make evident the difficulty of suppressing the dust generated by continuous-type mining machines.

AIRBORNE-DUST SAMPLING, MEASUREMENT, AND ANALYSIS

Dust Sampling

A detailed description of about 150 air sampling instruments was included in a manual of instruments (4). It contains a pertinent and comprehensive technical discussion introducing each instrument grouping and an appendix of tabular data useful to the industrial hygienist. Other published books pertaining to dust sampling, measurement, and analysis are included in the list of references of this paper (1, 44, 65, 89, 107). Many articles were published on these subjects, but only those describing equipment or procedures thought to be applicable to the mining industry are noted in this circular.

There is general agreement that the midget impinger is useful as a control instrument, but its value for evaluating the health hazard of dusts is questioned. The doubt stems from a growing acceptance of the concepts of respirable dust and selective sampling for assessing the health hazard. The genesis and evolution of these concepts were discussed by Morrow (140). Hatch and Gross (89) included descriptions of size-selecting instruments in a treatise on pulmonary deposition and retention of inhaled aerosols. They concluded that "there is no firm and final answer to the question: How to collect aerosol samples and how to express aerosol concentrations and composition."

Studies of size-selective samplers, suitable for fieldwork, were undertaken to resolve some of the problems associated with an accurate assessment of hazards to health from inhaled uranium aerosols. One such study (93) was conducted in uranium mills in New Mexico, using May preimpingers followed by macroimpingers and several models of small cyclones followed by membrane filters. Retention characteristics were determined for the preimpinger and four models of cyclones, and compared with upper respiratory track retention curves. The effects of sampling rate, of agglomeration and density of sampled dust, and of variation of outlet diameter on the collecting efficiency of cyclone collectors were also investigated. Another study (120) consisted of developing and using a family of size-selective air samplers for field survey work. Each sampler consisted of a cyclone collector followed by an efficient filter and operated at a flow rate suitable to a particular suction source. Sampling rates ranged from 0.9 lpm to 40 cfm. With these samplers, relative proportions of "respirable" and "nonrespirable" dusts were determined for various operations in the uranium and beryllium industries.

Following the trend to size-selective dust sampling, the Division of Occupational Health of the Pennsylvania Department of Health reported an investigation of gravimetric dust sampling (157). The performance characteristics of cyclones and horizontal elutriators were studied.

In the conduct of the environmental phase of the coal miners' pneumoconiosis study, the Bureau of Mines was confronted with the problem of sampling procedure. In reviewing the problem it was stated (178) that instrumentation should be based upon the following fundamental concepts:

1. This survey is concerned only with hygienically significant dust.

2. It should determine, as well as possible, the hygienically significant dust in the breathing zone of coal mine workers.

3. It should simultaneously determine the hygienically significant dust in the work area.

4. The relationship between data obtained from the breathing zone and corresponding information obtained from the work area must be established.

5. Measurements should be made on a time weighted, full shift basis.

6. The survey should separately identify the dustiness exposure of significantly different mining operations.

7. Compositional analysis, especially for silica and ash, should be made.

Guided by these concepts, laboratory and field tests of various dust sampling instruments were undertaken by the Bureau of Mines to determine their utility. A battery-operated midget impinger pump and a battery and pump combination for 8 to 10 hours operation of a personal sampler were developed. Both are intrinsically safe. The personal monitor consists of a 10-mm cyclone separator followed by a membrane filter. It has a flow rate of 2.8 lpm, and the dust collected on the membrane filter is determined by weighing. The tests included simultaneous sampling with the midget impinger apparatus, the personal monitor, and an Isleworth Gravimetric Dust Sampler. An empirical relationship of 5.6 million particles per cubic foot (mppcf) equivalent to 1 mg of respirable dust per m^3, was derived from the midget impinger and Isleworth sampler data (96). An empirical relationship of 17 mppcf equivalent to 1 mg of respirable dust was derived from additional personal monitor data. The quartz content of the respirable dust samples obtained with the personal monitor and the Isleworth sampler can be determined by infrared spectroscopy. A 0.35 to 0.45 milligram portion of a sample pelletized with potassium bromide is required for analysis.

A preliminary study (25) was made of the composition of the respirable fraction of airborne coal dust. Samples were collected for long periods of time in a powerplant with an elutriator especially designed for fractional recovery. Results indicated that settled dust samples as commonly collected or samples of the parent coal are not representative of the respirable airborne coal dust. The total mineral content (ash) of the airborne coal dust increased as the particle size decreased. The concentration of silica in parent material and airborne particulate matter were also investigated (177). The data obtained from the study indicated that the free silica content of airborne dust samples collected within 6 feet of the dust-producing operation and the parent material were about the same. For samples collected at distances greater than 6 feet the data were inconclusive.

Two cascade impactors of new design have been described in recent publications. The first instrument (119) was found to be suitable for the rough estimation of particle size distribution of airborne materials commonly

encountered in industry. Particulates are collected at four impaction stages on two standard 1- by 3-inch glass microscope slides and on a 1-inch-diameter filter following the impaction stages. The second instrument (6) is composed of six collection stages, each having 400 impactor jets, and has a sampling rate of 1 cubic foot of air per minute. Having been calibrated by using unit density spheres, all particles collected with it are classified as aerodynamic equivalents of particles of known lung penetrability. Thus, it was claimed that the health hazard can be assessed on the basis of respiratory tract penetration. For a special study, the multijet sampler was calibrated by use of monodispersed aerosols of methylene blue dye and polystyrene latex (77). Collection efficiency characteristics were determined directly from the mass retained at the deposition sites. This was held valid, because concurrent size-distribution data on each aerosol generated indicated that values for number and mass median diameter were nearly equal. Experimental methods of aerosol generation, sampling, and mass determination were presented with representative data. Collection efficiency curves obtained for the various stages of the sampler were given with computed values of effective cutoff diameters. Simplicity and accuracy were cited as advantages of the calibration method. Another direct method has been devised for measuring cascade impactor stage efficiencies (58). The method makes use of a special two-stage configuration of the sampler being used. To employ the method, it is only necessary to measure the unnormalized density function of the particles collected on the second of two identical impactor stages. With this method an impactor stage can be calibrated in a few hours.

Errors inherent in methods used to interpret cascade impactor data were discussed in a recent publication (130). Two methods of interpretation are commonly used. In one, the stage constants of the impactor are effective cutoff diameters, and it is assumed that a given stage collects all particles greater than its effective cutoff diameter. In the other, the stage constants are mass median diameters, and it is assumed that the sample collected at a given stage always has the same mass median diameter. Errors in interpretation arise, because stage constants of both types are functions of the mass distribution of the aerosol being sampled. The magnitude of these errors was calculated for a Casella impactor, and it was found that effective cutoff diameters are more reliable as stage constants than are mass median diameters.

Limited use has been made of the cascade impactor for sampling in ducts and stacks. A dust probe was designed for a Casella cascade impactor (82). The design includes probe nozzles, an arrangement for preventing deposition of aerosol on the first stage prior to the actual sampling period, and a timing control system which permits reproducible sampling periods as brief as 0.6 second.

A miniaturized midget impinger flask was developed for possible use as a personal monitor (117). The design is based on a threefold reduction of the midget impinger flask dimensions. Dust collection performance data indicated that, at the proper flow rate, the particle collection characteristics of the microimpinger are comparable to those of the midget impinger.

An improved high-volume air sampler having a weighable support for fibre glass filters was described (173). Novel features of the equipment include a filter support which permits rapid filter changing and an arrangement for accurate airflow measurement. A light-weight high-volume electrostatic precipitator was announced (121). Reportedly, it collects airborne particles of all sizes with high efficiency at a sampling rate of 27 cubic feet of air per minute. The sample is collected on a single tube 1-1/3 inches in diameter and 12 inches long. It can be used with a cyclone precollector, simulating upper respiratory retention, for two-state sampling, without a significant reduction in sampling rate.

Two flow rate regulators, each working on a different principle, were developed to maintain constant rates of flow in high-volume air samplers (87). Both a bypass regulator and a series regulator showed satisfactory control by regulating the airflow of approximately 35 cfm within ±4 percent over a pressure range of 13 to 16 inches of water. Two filtration-type air samplers were tested in turbulent and positive directional air streams to determine if sampling is dependent on orientation of the sampling instrument (79). In turbulent air no bias due to orientation was found. In a directional air stream, a sampler head facing into the air stream collected more dust by a factor of two.

Aerosol sampling procedures for obtaining electron microscope specimens were outlined and discussed in an article (27) which also includes a comprehensive list of references pertaining to sampling methods.

The millipore filter technique used since 1957 by the Tennessee Valley Authority for assessing dusty conditions in handling coal at power generating plants has been developed further (143). A piece of filter is prepared for counting and sizing by placing it on a microscope slide and subjecting it to acetone vapors which results in an even, clear, glazelike finish to the filter with the dust particles sealed to the slide in a single plane. It has been reported that routine use of membrane filters was simplified by the design of a small inexpensive filter holder which has advantages over commercially available units (174). Techniques for determining sample collection rates directly from vacuum-gage readings and for preparing samples for use with internal proportional counters were described in the same report.

The reproducibility and the relationship of dust counts determined by a Southern Research Institute Aerosol Photometer, a midget impinger, and a membrane filter sampling procedures have been investigated (26). Coefficients of variation of concentrations of airborne limestone dust were determined to be 9.4, 15.2, and 22.2 percent for the aerosol photometer, membrane filter, and midget impinger, respectively. Limestone dust concentrations by midget impinger were numerically equivalent to aerosol photometer dust concentrations with its threshold setting at 0.8 micron. Best agreement of membrane filter and aerosol photometer concentrations for coal dust occurred at the 0.3-micron threshold setting. Similar results were obtained with the aerosol photometer when used in an underground metal mine (45). The results of the field tests indicated that it can give good results, calibration is very important for acquiring accurate count and size distribution data, instrument maintenance is not excessive, and its operation is reliable.

Concern has been expressed over the need for further standardization of the procedure for impinger sampling to assure compliance with the threshold limit values recommended annually by the American Conference of Governmental Industrial Hygienists (169). The following recommendations have been made:

1. The inlet to the impinger should be held between the dust source and the worker's nose and mouth and no more than 2 feet from the worker's nose and mouth.

2. The samples should be spaced throughout a shift or complete cycle of operations. The samples should be taken at regular intervals or at times chosen at random beforehand. If samples are taken at regular intervals, care should be taken to see that the interval does not coincide with any other regular cycle of events which might be related to dustiness.

3. The environment complies with the threshold limit value document when the estimated average concentration is less than that given by the following formula:

$$C = TLV - k(\text{range}),$$

where C = maximum average concentration for compliance,
TLV = threshold limit value,
Range = difference between maximum and minimum results, and
k = a constant related to the number of samples taken (refer to the following table).

k values for the range

Number of samples	k
32	0
10-31	0.1
6-9	0.2
5	0.3
4	0.4
3	0.8
2	2.9

Particle Sizing and Counting

Centrifugal sedimentation and electron microscopy coupled with electronic counting were compared for measurement of particle-size distributions of calcium phosphate and silica particles below 5 microns (95). Weight-size distributions from the two techniques agreed within experimental error. Excessive time required for determination and inaccuracies due to Brownian motion make the use of the centrifugal sedimentation technique impractical for sizing particles smaller than 0.1 micron in size.

The relative merits of methods of automatically counting and sizing particles were discussed (54). It was noted that (1) light scattering methods are readily amenable to automation and at present offer the only reliable means for directly analyzing aerosols over a range of sizes extending from molecular dimensions to the lowest sieve size; (2) planar field scanning has not fulfilled early expectations, and instruments utilizing this principle need further improvement before they can be regarded as general utility instruments; and (3) the Coulter Counter has the advantages of simplicity, flexibility, and low operating cost, and is an obvious choice for applications within the size range specified for particles dispersed in a liquid electrolyte.

The Bureau of Mines developed a procedure for using the Coulter Counter to determine dust concentrations from midget impinger samples collected in coal mines (12). The procedure was found to be more precise for dust counting than the Bureau of Mines standard microprojector method (7). The gain in precision is due primarily to the increase in the number of particles counted. Counting time is reduced and particle-size data can be obtained readily. The problems of instrument calibration (131) and coincidence phenomenon (164) were considered in the course of the investigation.

Two basic errors in particle counting by the light-field microscope method have been investigated (73). These were the within-counter and between-counter variability when counting particles contained on a given field. The study indicated that the between-counter variability was about twice that of the within-counter variability. The within-counter variability was about 22 percent and was the standard deviation expressed as percentage of the within-counter mean. Optimum dust density for counting was found to be between 40 to 60 particles per field.

The effect of viscosity of the suspension medium on the settling time of particles in suspension in a counting cell has been investigated (83). A family of curves was prepared which allows quick approximation of expected settling time in counting cells, as defined by Stokes' law, when minimum detectable diameter, particle density, and medium density and viscosity are known. It was concluded that if consideration of media viscosities and particle densities is neglected, the data yielded by the fixed settling-time counting procedure may not represent the actual concentration of dust on a common basis for comparison with threshold limit values or other data.

A statistical comparison was made of equivalent area counts and dust concentrations determined from microprojector and light-field microscope count data (203). The equivalent area count of the microprojector deviated significantly from those of the microscope for 55 of the 79 samples, or 69.6 percent. A similar deviation was found for the dust concentrations. In each case it was found that the microprojector produced higher results, and the average ratio was 1.52 for microprojector to microscope equivalent area counts.

Thirty persons of varying experience, determined the particle-size distribution of a prepared set of 18 dust slides for comparative purposes and the results were evaluated statistically (17). Being in practice rather than having long experience seemed to be the main criterion of accuracy in size

measurement by microscope. Another comparison was made of the aerosol sampling and sizing techniques of nine different laboratories (76). Most of the work of the study involved submicron aerosols, which were sized by electron microscope techniques. Variations up to ±10 percent in count median diameter and geometric standard deviation were found in comparing sizing results. Count median diameters determined on the basis of maximum horizontal diameter (Feret's diameter) were approximately 10 percent higher than those determined on the basis of equivalent area (projected diameter). Variation in count median diameter remained at ±10 percent with eight different air sampling instruments, whereas variation in geometric standard deviation increased to ±15 percent.

A multistage sizing technique has been described (158) which is applicable to particle sizes ranging from 0.3 to 500 microns. Successive particle-size counts of several hundred particles are made, each at a lower magnification as required by the particle-size range of the sample. With each successive count, the particles below a successively larger size are not counted. The ratio of the number of particles above to those below a specified size, determined from the preceding counts, are used to calculate the number of particles in the omitted size ranges for the successive counts. The size-count data are converted to cumulative size-frequency data, regarding the particles as spheres. The size-frequency data are plotted on log probability graph paper to determine the geometric mean size and geometric standard deviation on a number basis. The reported geometric mean size on a weight basis is determined by using the following equation:

$$\ln X_{vg} = \ln X_{ng} + 3.0 \ln^2 o_g$$

where X_{vg} = geometric mean by weight,
X_{ng} = geometric mean by count,
o_g = standard geometric deviation.

Procedures were recommended for estimating the statistical error associated with presentation of sizing data based on conventional count, area, or weight distributions (56-57). Tabular and graphical forms are suggested for presentation of sizing data. It was recommended that

1. The original sizing data be presented, not only the total number of particles sized, but the number per defined class interval.

2. The sizing results be presented as a frequency histogram or a cumulative frequency distribution.

3. The errors associated with each class interval and estimated as $f_i^{1/2}$ be superimposed on the frequency polygon or at least indicated in a table in the body of the text.

4. If "goodness of fit" techniques are applied to the sizing data and indicate a high probability for adherence to the log-normal distribution, then the use of the characterizing parameters, geometric mean, and standard geometric deviation, is justified.

Some areas in which the electron microscope has been employed for solution of occupational health problems were pointed out in a recent publication (91). In one instance, under the optical microscope, a large number of very small particles were observed, which lowered the median particle size well below that found in a similar type sample from a previous study. When the samples were examined under the electron microscope, two types of material were seen. One was the typical mineral dust of concern, and the other was a very small fumelike substance, later identified as primarily coal smoke and only present in the air during the heating season.

A new method was developed for preparation of carbon-coated grids for electron microscope applications (162). Particularly suited for quantity output, it was claimed to be relatively simpler, faster, more efficient, and less expensive than other commonly used techniques.

Dust Analysis

Procedures used routinely in the laboratories of the U.S. Public Health Service, Division of Occupational Health for the X-ray diffraction analysis of industrial dust were presented (183) with particular reference to new techniques for the collection and analysis of airborne dust when the total weight of sample is about 1 milligram. The composition is given of a photographic developer for X-ray diffraction films which has low fogging properties and which provides a wide range, linear intensity-density relationship. The use of beryl as an internal standard for the quantitative determination of quartz in industrial dust is discussed, and results obtained by chemical methods are compared with results obtained by X-ray diffraction methods.

Comparison of X-ray diffraction, chemical, and dispersion staining methods for the determination of quartz in dust samples revealed a high degree of correlation among the three analytical methods (72). Dust samples from a variety of sampling instruments were analyzed chemically by a phosphoric acid treatment method, by a phase contrast dispersion staining method, and by X-ray diffraction. The correlation of pairs of sampling methods were consistently good except for analysis of the less than 5-micron fractions. Possible sources of disagreement among the sampling methods used were judged to be the loss of an appreciable mass of quartz during heating of the sample in hot phosphoric acid, the presence of other material having indices of refraction similar to quartz, and a disparity between particle-size distribution of the quartz and nonquartz fractions of the sample. It was concluded that, for the same dust sample, the quartz content yielded by one commonly used analytical method may differ from that yielded by another commonly used method.

A study of the precision of the phosphoric acid method (182) gave a mean standard deviation of 0.34 in the analysis of typical dust samples containing from 3 to 50 percent quartz. A reduction of digestion time was proposed for minimizing the loss of quartz from the less-than-5-micron fraction of airborne dust. The phosphoric acid method can be extended to samples of airborne dust as small as 2 milligrams by spectrophotometric determination of the quartz as molybdisilicic acid.

A technique has been described for quantitative determination of asbestos in airborne dust samples by X-ray diffraction analysis (59). Samples of airborne asbestos collected on filters are redeposited on membrane filters to assure uniform distribution over the entire filter. The prepared filters are mounted in a diffractometer for qualitative and quantitative analysis. This procedure, which makes use of external standards prepared from pure asbestos materials, is applicable to quantitative determination in the 1- to 8-milligram range for crocidolite and amosite and in the 1- to 10-milligram range for chrysotile. This procedure may be used for analyzing bulk samples by dry-grinding them to proper particle size before preparing the membrane filter mounts. A technique was also described for X-ray diffraction analysis of bulk or settled dust samples for chrysotile (60). An internal standard, aquamarine, is used in the quantitative determination of the asbestos material. The method can be applied to 1-gram samples of materials containing a minimum of 5 percent chrysotile.

LEGISLATION

Except as provided by the Federal laws noted, the regulation dust control in mining, tunneling, and quarrying is under State jurisdiction. A Bureau of Mines report covering 1958 through 1960 summarized the various State administrative organizations (10).

Federal Government

To promote health and safety in the metal and nonmetallic industries the 89th Congress passed the Federal Metal and Nonmetallic Mine Safety Act (128, 190), which was approved September 16, 1966. The major responsibility for administering the provisions of the act is vested in the Bureau of Mines. With regard to dust control, it authorizes the Secretary of the Interior to inspect and investigate mines, as defined, for the purpose of obtaining, utilizing, and disseminating information relating to the causes of occupational diseases originating in such mines. It also authorizes him to promulgate health and safety standards and to designate as mandatory, standards which deal with conditions or practices of a kind which could reasonably be expected to cause death or serious physical harm. No standards had been promulgated by the end of the year 1967.

Public Law 376, 89th Congress, approved March 26, 1966 (37, 129, 189), extended the provisions of Title II of the Federal Coal Mine Safety Act to all underground coal mines regardless of the number of persons employed. The provisions of the amended act and the Federal Mine Safety Codes pertaining to control of coal mine dust are as follows:

(1) Where underground mining operations raise an excessive amount of dust into the air; water or water with a wetting agent added to it, or other effective method, shall be used to allay dust at its source. This mandatory provision from which anthracite mines are excepted is intended to control fire and explosion hazards only.

(2) The dust resulting from drilling in rock shall be controlled by the use of permissible dust collectors or by water or water with a wetting agent, except as provided for short periods of exposure (41). This is an advisory provision applicable to all underground mines.

(3) Men exposed for short periods to gas-, dust-, fume-, and mist-inhalation hazards shall wear permissible respiratory equipment. When exposure is for prolonged periods, other measures to protect the workmen or to reduce the hazard shall be taken. This is an advisory provision applicable to all underground mines.

(4) Men exposed to dust-, fume-, and mist-inhalation hazards shall wear permissible respiratory equipment. This is an advisory provision applicable to all strip mines.

Under provisions of the Walsh-Healey Public Contracts Act the Department of Labor issued "Radiation Standards for Mining" (35-36), effective December 14, 1967. In it a working level is defined as any combination of radon daughters in one liter of air which will result in the ultimate emission of 1.3×10^5 mev of potential alpha energy. A working level month is defined as the exposure received by a worker breathing air at one working level concentration for 4-1/3 weeks of 40 hours each. Control of occupational exposure is required so that no individual will receive an exposure of more than 1.8 working level months in any consecutive 3-month period and no more than 3.6 working level months in any 12-month period. Until January 1, 1969, mines will be considered in compliance that have conditions that would result in an exposure of not more than 12 working level months in any 12 consecutive months.

State Government

The States of Alaska, Arizona, Idaho, Michigan, Montana, Nevada, New Mexico, Oklahoma, Pennsylvania, South Dakota, Utah, Virginia, West Virginia, and Wyoming made changes in mining laws during the period 1963 through 1967. Regulations pertaining to dust control, included in these laws, are summarized as follows:

Alaska

The "Mine Safety Regulations, 1963" (2) of the State of Alaska applicable to mines other than coal, requires that an employer shall provide water or some other effective means to collect or allay dust created by rock drilling or boring machines which create injurious quantities of dust. No employee shall use any drilling machine without the use of water or other dust preventative. Workmen who are exposed to dusts, metal fumes, and smokes, in amounts above established limits, shall be provided with proper protective devices. All underground working places shall be provided with an adequate quantity of fresh healthful air. Operators shall equip chutes from which dusty ore or rock is taken with efficient sprinklers or other devices to prevent the escape of dust into the air. Mills, ore houses, or treatment plants where dry or dusty ore or rock is handled shall be supplied with clean water and suitable sprinkling equipment which shall be used to allay dust, or equivalent

protection shall be provided. Rock drills shall be equipped with an effective means to collect or allay dust. When workmen must be exposed to dust or fume hazards for only short periods of time, they shall wear U.S. Bureau of Mines approved respiratory devices, but when exposure is for prolonged periods, other means of protection must be taken.

Requirements of the Regulations applicable to coal mines include the provisions of the Federal Mine Safety Code for Bituminous-Coal and Lignite Mines of the United States, Parts I and II, and the Code of the Federal Regulations of the United States, Title 30, Parts 211 and 216.

Arizona

The "Mining Code of the State of Arizona" (15) provides for a State mine dust engineer responsible for inspecting each mine in the State to determine whether or not a hazardous dust condition exists therein and recommending methods of remedying such conditions. A hazardous dust condition, as defined by law, is deemed to exist where the breathing zone of an employee while engaged in the performance of his work contains more than 10 million particles of airborne dust, between 1 and 5 microns in largest dimension, per cubic foot of air. However, if the free-silica or asbestos content of such airborne dust does not exceed 10 percent, a dust hazard shall not be deemed to exist unless such particles exceed 100 million per cubic foot of air. The State's Mine Safety Rules require that all drilling in open pits must be done wet, all holes drilled underground must be collared and drilled wet, muck piles must be wetted down before moving, and sprinkling devices must be installed at loading pockets and chutes to prevent the escape of dust into the air.

Idaho

The Idaho Safety Code (94) recognizes that in all quartz and lode mining there is a silicosis hazard which must be controlled. A dust concentration of 10 million particles or more per cubic foot of air, originating from any rock formation having more than 10 percent by weight free silica (SiO_2) is deemed prima facie injurious. A dust concentration of 50 million particles or more per cubic foot of air, originating from any rock formation having less than 10 percent by weight free silica also is deemed prima facie injurious. Environmental atmospheres, when not regulated by Idaho statutes, must meet standards set forth by the American Conference of Governmental Industrial Hygienists.

According to the code, every working place where dust in detrimental quantities emanates shall be supplied with water for the purpose of preventing dust from arising. In every mine, mill, rock crushing plant, or any other operation where men are exposed to dust or fumes in harmful quantities, some mechanical or other means or method to control this condition must be used. Operators must furnish rock drilling machinery equipped with a water jet or spray or other means equally efficient to prevent the escape of dust; it is the employee's duty to use said appliance for the prevention of dust. When no other method can be used to prevent exposure to injurious dust, fumes, or gas concentrations, personal respiratory protection equipment, approved by the U.S. Bureau of Mines, shall be used.

Michigan

Minimum standards for control of health hazards in mining, tunneling, and other underground operations (137) were prepared by the Division of Occupational Health, Michigan Department of Health, in cooperation with the Division of Industrial Hygiene, City of Detroit, to fill the need of contractors, State and local governments, and others involved in letting contracts for underground operations. The standards require that clean air be supplied to all underground areas in sufficient quantity to prevent the buildup of toxic dusts or gases to concentrations in excess of maximum allowable concentrations, as listed annually by the Michigan Department of Health, that wet drilling equipment be used when drilling holes in rock or concrete, and that, where dry rock or other material is being handled, the muck pile shall be wetted prior to mucking and kept wet during the mucking operation in order to control dust.

Act 264 of the Public Acts of 1967 (136) provides for the inspection of mines, for the health and safety of persons employed in and about mines, for the appointment of mine inspectors, and creates a mine safety board in the Department of Labor. The act requires that the mine safety board formulate rules for the protection of life, promotion of health and safety, and prevention of accidents in the metallic and nonmetallic mine industry of the State. The board has yet to adopt the said rules.

Montana

The "Minimum Safety Standards for Mining, Quarrying, Milling, and Smeltering Operations in Montana" (139) requires that every enclosed working place be sufficiently well ventilated and free from harmful quantities of dust or noxious fumes; that the maximum allowable concentrations of alpha emitting decay products of radon should not exceed 300 micromicrocuries per liter of air or other limiting quantity as established by the U.S. Bureau of Mines; that rock drilling in underground mines be prohibited unless the dust is controlled by wet drilling or other approved means and the water flow is maintained continuously whenever the drill is in operation; that no primary blasting be done in a mine during the working shifts unless the ventilation currents are arranged to minimize circulation of dust, smoke, and fumes from the blast in areas where other men are working; that underground muck piles be wet down before mucking begins and be kept wet during the entire mucking operation to control the dust, if dust conditions adverse to health exist; that harmful dusts, fumes, and mists giving rise to harmful exposure of employees be controlled by effective means such as general, local, or pressure ventilation; and that the use of permissible respiratory protective equipment be regarded as emergency protection against occasional and/or relatively brief exposure and if exposure is in excess of 1 hour per shift, other control measures be used.

Nevada

"Nevada State Mining Laws, 1966 Edition" (148) requires that machinery for drilling holes in any stope or raise in ground that causes dust from drilling be equipped with a water jet or spray or other means equally

efficient to prevent the escape of dust. The drilling machine appliance for the prevention of dust must be used when the machine is operated. All chutes from which dusty ore or rock is taken shall be equipped with a sprinkler or other device with which to effectively dampen such rock or ore to prevent the escape of dust during removal. Every ore house where dust, ore, or rock is sorted shall be supplied with suitable clean water which shall be used for allaying the dust. There shall be a dust control program for enclosed milling, crushing, or mineral processing operations. Permissible concentrations of silica-bearing dusts in any milling, crushing, or mineral processing operations shall be designated within limits as follows:

Description	Million particles per cubic foot of air (0.5 to 5 microns largest dimension)
High (above 50 percent free silica)......	5
Medium (5 percent to 50 percent free silica).................................	20
Low (below 5 percent free silica)........	50

New Mexico

The "New Mexico Mine Safety Code for All Mines, Including Opencut and Open-pit" (149) provides for a dust and mine gas engineer. He performs tasks assigned by the State mine inspector, with special attention being given to testing for gas in mines and excavations and to making dust counts. The code also requires that in underground metal mines, machinery for drilling or boring holes must be equipped with a water jet or spray or other equally effective means for allaying dust, that in the sinking of shafts drilling shall be done wet, and that every plant in which dry or dusty ore or rock is treated shall have water and sprinkling equipment which shall be used for allaying the dust, or equivalent protection shall be provided.

Oklahoma

Section 8 of Senate Bill No. 166 amended Title 45 of the Oklahoma Statutes 1961, Sec. 528 (150), and provided that in coal mines, water must be used on cutter bars on all mining machines while cutting rock, and water or an approved dust collector must be used for control of dust from rotary-roof or rock drills.

Pennsylvania

The revised "Bituminous Coal Mining Laws of Pennsylvania" (160-161) require that coal dust or other dust in suspension in unusual quantities be allayed by sprinkling or by using other dust allaying or collecting devices, that men exposed to dust for short periods of time shall wear respiratory protective equipment, and that men exposed to dust for prolonged periods shall have protection from dust by use of approved dust collectors or dust allaying methods.

South Dakota

The "South Dakota Mine Safety Code for All Mines Including Quarries and Open-Pit" (181) requires that underground metal mine drilling machines be equipped with water jets or sprays sufficient to allay dust from drilling or that other equally effective means be used to prevent the inhalation of dust.

Utah

"General Safety Orders Covering Metal and Non-Metal Mines, Mills, Smelters, Tunnels, Quarries, Gravel Pits, Etc., In the State of Utah" (191) requires that wherever drilling or other operations cause excessive quantities of dust in the working atmosphere, effective dust allaying or collecting facilities shall be provided to keep the dust content at or below accepted threshold limit values or maximum acceptable concentrations. The TLV or MAC as given in the last report of the American Conference of Governmental Industrial Hygienists, or some other nationally recognized authority, will be used as a guide in establishing acceptable limits of concentrations. When a workman is exposed to toxic or irritating dust, gas, or fume that cannot be controlled by practical means, he shall be provided with and wear U.S. Bureau of Mines approved respiratory equipment. Blasting underground during the shift should be avoided, but when blasting is done before the end of the shift, working places shall be cleared of smoke and dust before men return. The working places of every underground uranium mine shall be provided with sufficient ventilation to maintain radon-daughter concentrations at acceptable levels whenever the mine is being operated. The atmospheric concentration of radon daughters where men work should not exceed 300 micromicrocuries per liter (WL) as determined by the field method detailed in U.S.A. Standards Institute N7.1-1960 (187), and every operator shall make a reasonable effort to attain said standard. In crushing, screening, and processing plants, effective dust control measures shall be taken or personal protective equipment used wherever employees are exposed to dust in excessive quantities.

"General Safety Orders Utah Coal Mines" (192) requires that a pipeline system shall be provided for wetting the rib, roof, and floor surfaces for a distance of at least 40 feet outby the face of each working place. Where underground mining operations raise an excessive amount of dust into the air, water, water with a wetting agent added to it, or other effective method shall be used to allay such dust at its source. Each continuous-miner section shall be ventilated with fresh air so directed that the dust and gas created by continuous-miner operation shall be diverted away from the operator. A coal breaker shall be permitted underground if adequate dust allaying facilities are provided. Where coal is dumped at or near intake openings, provisions shall be made to prevent the dust from entering the mine. Men exposed for short periods to gas, dust, fume, and mist inhalation hazards shall be provided with and wear approved respiratory equipment. When the exposure would be for prolonged periods, other measures to protect or reduce the hazard shall be taken.

Virginia

The "Mining Laws of Virginia, 1966" (194) requires that where mining operations raise an excessive amount of dust into the air, water or water with a wetting agent added to it, or other effective methods shall be used to allay such dust at its source; and that men exposed for short periods to gas-, dust-, fume-, and mist-inhalation hazards shall wear permissible respiratory equipment, but when exposure is for prolonged periods, other measures to protect the workmen or to reduce the hazard shall be taken.

West Virginia

The "Mining Laws of West Virginia, 1967" (199) requires that coal dust and other dust in suspension in unusual quantities shall be allayed by sprinkling or using other dust allaying devices. Where coal is dumped at or near air intake openings, reasonable provisions shall be made to prevent dust from entering the mine. Men exposed for short periods to gas-, dust-, fume-, or mist-inhalation hazards shall wear permissible respiratory equipment, but when exposure is for prolonged periods, dust shall be controlled by the use of permissible dust collectors, or water, or other approved methods.

Wyoming

The "Wyoming Non-Coal Mining Law, 1966" (200) requires the use of some mechanical or other means to alleviate conditions where dust or fumes in harmful quantities result from mining, milling, or processing operations; and the use by personnel of such protective devices as are furnished by the operator. An air velocity of 25 linear feet per minute must be maintained in each working place. The end of ventilation tubing or pipe, when used, must be kept within 40 feet of the face of working places. Operators of underground mines must test the mine atmosphere for dangerous gases and dust at sufficient intervals to warrant safe operation. Each operator of a uranium mine or processing plant shall, as far as is reasonably possible, maintain conditions that conform to the requirements of U.S.A. Standards Institute N7.1-1960 (187) or its amendments, and make radioactivity surveys at intervals recommended by the State inspector of mines.

CONTINUING RESEARCH

Federal and State Government agencies (40, 106, 198), technical societies (102), universities (152), and industrial research organizations (34, 78, 88, 171) conduct, sponsor, or promote research related to dust generation, behavior, and control. Mining companies and equipment manufacturers (21, 103) conduct research, as required, for resolving dust problems specific to their own operations.

REFERENCES

1. Adams, Donald F., ed. Air Pollution Instrumentation. Instr. Soc. America, 1966, Pittsburgh, Pa., 75 pp.

2. Alaska, Department of Natural Resources, Division of Mines and Minerals. Mine Safety Regulations, 1963, 89 pp.

3. Alston, G. L. Advances in Rockdusting Procedures. Mechanization, v. 25, No. 1, January 1961, pp. 46-48.

4. American Conference of Governmental Industrial Hygienists. Air Sampling Instruments, Cincinnati, Ohio, 3d ed., 1966, 480 pp.

5. _____. Threshold Limit Values for 1967, Cincinnati, Ohio, 1967, 26 pp.

6. Andersen, A. A. A Sampler for Respiratory Health Hazard Assessment. Am. Ind. Hyg. Assoc. J., v. 27, No. 2, March-April 1966, pp. 160-165.

7. Anderson, Floyd G. A Technique for Counting and Sizing Dust Samples With a Microprojector. Am. Ind. Hyg. Assoc. J., v. 23, No. 4, July-August 1962, pp. 330-336.

8. Anderson, Floyd G., and R. L. Evans. Drill-Dust Collectors and Drilling Equipment With Integral Dust-Collecting Systems Approved by the Bureau of Mines as of January 31, 1961. BuMines Inf. Circ. 8027, 1961, 28 pp.

9. _____. Dust Control in Mining, Tunneling, and Quarrying in the United States, 1955 Through 1957. BuMines Inf. Circ. 8021, 1961, 25 pp.

10. Anderson, Floyd G., R. L. Evans, and R. G. Peluso. Dust Control in Mining, Tunneling, and Quarrying in the United States, 1958 Through 1960. BuMines Inf. Circ. 8130, 1962, 23 pp.

11. _____. A Study of Dust-Control Methods for Continuous Mining of Coal. BuMines Inf. Circ. 8205, 1963, 14 pp.

12. Anderson, Floyd G., Thomas F. Tomb, and Murray Jacobson. Analyzing Midget Impinger Dust Samples With An Electronic Counter. BuMines Rept. of Inv. 7105, 1968, 8 pp.

13. Archer, Victor E., Harold J. Magnuson, Duncan A. Holaday, and Pope A. Lawrence. Hazards to Health in Uranium Mining and Milling. J. Occ. Med., v. 4, No. 2, February 1962, pp. 55-60.

14. Arentzen, Leif. Float Dust Control. Abs. in Coal Age, v. 70, No. 8, August 1965, pp. 97-99.

15. Arizona, State Mine Inspector. Mining Code of the State of Arizona. Issued by Verne C. McCutchan, July 1968, 32 pp.

16. Ashe, Harry B., and Donald E. Bergstrom. Twenty-Six Years' Experience With Dust Control in the Vermont Granite Industry. Ind. Med., v. 33, February 1964, pp. 73-78.

17. Baier, E. J. A Comparison of Particle-Size Measurements. Am. Ind. Hyg. Assoc. J., v. 22, No. 4, August 1961, pp. 307-312.

18. Baier, E. J., and R. Diakun. Comparison of Dust Exposures in Pennsylvania Anthracite and Bituminous Coal Mines. Am. Ind. Hyg. Assoc. J., v. 25, No. 5, September-October 1964, pp. 476-480.

19. _____. Environmental Dust Study of Anthracite Coal Mines of Eastern Pennsylvania. J. Occ. Med., v. 5, No. 8, August 1963, pp. 396-403.

20. _____. Pneumoconiosis Study in Central Pennsylvania Coal Mines, II Environmental Phase. J. Occ. Med., v. 3, No. 11, November 1961, pp. 507-521.

21. Barrett, A. Lee. Machine Design: Ventilation, Dust Control, and Other Safety Features. Trans. 55th Nat. Safety Cong., Coal Min. Sessions, 1967, pp. 22-25.

22. Belton, Arthur E. Ventilating for Continuous Miners in Northern West Virginia. Coal Age, v. 69, No. 3, March 1964, pp. 74-78.

23. Beverly, R. G. Radiation Control in Uranium Mines and Mills. Min. Cong. J., v. 47, No. 4, April 1961, pp. 77-82.

24. Beverly, Robert G., and Vernon J. Bishop. Air Sampling Limits Radiation Exposure in Colorado Uranium Mines. Min. Eng., v. 13, No. 8, August 1961, pp. 962-965.

25. Bianconi, W. O., and E. D. Meyers. Preliminary Studies in the Chemical Composition of the Respirable Fraction of Airborne Coal Dust. Tennessee Ind. Hyg. News, v. 43, No. 4, Fall 1961, pp. 1-5.

26. Bianconi, W. O., and F. W. Thomas. Reproducibility of Aerosol Photometer, Midget Impinger and Membrane Filter Counts for Limestone and Coal Dusts. Am. Ind. Hyg. Assoc. J., v. 26, No. 4, July-August 1965, pp. 362-365.

27. Billings, Charles E., and Leslie Silverman. Aerosol Sampling for Electron Microscopy. J. Air Pollution Control Assoc., v. 12, No. 12, December 1962, pp. 586-590.

28. Blackburn, J. A. Coordination of Dust Conditions Found in Bituminous Coal Mines. Proc. Pennsylvania Governor's Conference on Pneumoconiosis (Anthraco-Silicosis), Harrisburg, Pa., Nov. 30-Dec. 2, 1964, p. 125.

29. Boyle, Francis R. Metering Rock Dust. Proc. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 9-10, 1965, pp. 138-148.

30. Bronakoski, Adam. High Capacity Fans Mounted on Boring Type Continuous Miners for Ventilation and Dust Control. Pres. at Western Pennsylvania Safety Eng. Conf., Pittsburgh, Pa., Mar. 29, 1967, 7 pp. Available for inspection at the Bureau of Mines Health and Safety Research and Testing Center, Pittsburgh, Pa.

31. Brown, Murray C. Pneumoconiosis in Coal Mines. Min. Cong. J., v. 51, No. 8, August 1965, pp. 44-48.

32. Buch, John W. Hydraulic Mining of Anthracite: Engineering Development Studies. BuMines Rept. of Inv. 6610, 1965, 24 pp.

33. Buch, John W., and Ivor L. Williams. Hydraulic Mining of Anthracite. Min. Cong. J., v. 48, No. 7, July 1962, pp. 22-28.

34. Buchanan, William W., ed. Industrial Research Laboratories of the U.S. Bowker Associates, Inc., Washington, D.C., 1965, 12th ed., 746 pp.

35. Bureau of Labor Standards, U.S. Department of Labor. Notices. Radiation Standards for Mining. Standard Forms for Recording Radiation Exposure. 32 Fed. Register p. 17693 (Tuesday, Dec. 12, 1967).

36. _____. Rules and Regulations. Radiation Standards for Mining. 32 Fed. Register p. 15641 (Friday, Nov. 10, 1967); 41 Code Fed. Regulations part 50-204.321.

37. Bureau of Mines. Federal Coal Mine Safety Act, as Amended 30 U.S.C. 451. Title I - Advisory Powers Relating to Health and Safety Conditions in Mines. Title II - Prevention of Major Disasters in Mines. January 1967, 63 pp.

38. _____. Proposed Rule Making. Electric Motor-Driven Mine Equipment and Accessories (BuMines Schedule 2G) 32 Fed. Register, pp. 18098-18113 (Tuesday, Dec. 19, 1967); 30 Code Fed. Regulations parts 18, 34.

39. _____. Report on Roof Bolting in Coal Mines for 1966, 1 p. Data compiled from Bureau of Mines records available at the Bureau of Mines Health and Safety Research and Testing Center, Pittsburgh, Pa.

40. Bureau of Mines, Coal Research. Review of Bureau of Mines Coal Program, 1966. BuMines Inf. Circ. 8357, 1967, 119 pp.

41. Bureau of Mines, Health and Safety Activity. The Federal Coal Mine Safety Act and Federal Mine Safety Codes: Interpretations and Applications. BuMines Inf. Circ. 8149, 1963, 26 pp.

42. Bureau of Mines, Health and Safety Research and Testing Center, Branch of Health Research. Study of Dust Control by Water Infusion at the Olga No. 1 Mine, Olga Coal Co., Coalwood, W. Va. Internal report, Pittsburgh, Pa., 1965, 55 pp. Available at the Bureau of Mines Health and Safety Research and Testing Center.

43. Burgess, James V. New Methods and Materials in Maintaining Continuity in Face Ventilation. Proc. 76th Ann. Meet. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 13-14, 1962, pp. 75-80.

44. Cadle, Richard D. Particle Size: Theory and Industrial Applications. Reinhold Publishing Corp., New York, 1965, 390 pp.

45. Channel, James K., and Roy J. Hanna. Experience With Light Scattering Particle Counters. Arch. Environ. Health, v. 6, No. 3, March 1963, pp. 92-106.

46. Coal Age. Bulk Rockdusting for Efficiency and Economy. V. 69, No. 8, September 1964, pp. 82-86.

47. _____. Coal Age Operating Guide, Longwall Mining. V. 70, No. 2, February 1965, pp. 89-104.

48. _____. Longest Coal Belt System, Television Controls. V. 68, No. 7, July 1963, pp. 78-83.

49. _____. Modern Bulk Rockdust Handling. V. 69, No. 2, February 1964, pp. 107-110.

50. _____. Successful Hydraulic Mining on 72 Deg. V. 67, No. 1, January 1962, pp. 80-84.

51. _____. Ventilating Today's Coal Mines. V. 66, No. 7, July 1961, pp. 208-210.

52. Coal Mining and Processing. Bulk Rock Dusting Promotes Safety. V. 2, No. 4, April 1965, pp. 22-24.

53. Connor, C. W., Jr. Separate-Split Ventilation of Continuous-Mining Faces. Coal Age, v. 66, No. 8, August 1961, pp. 79-82.

54. Connor, P. Automatic Counting and Sizing of Particles. Ind. Chemist, v. 39, No. 2, February 1963, pp. 69-74.

55. Cooley, G. Edward. Bulk Rock Dusting - Another Forward Step. Min. Cong. J., v. 49, No. 5, May 1963, pp. 43-46.

56. Corn, Morton. The Effect of Dust Particle Orientation on Particle Size Determined by Microscopic Techniques. Am. Ind. Hyg. Assoc. J., v. 25, No. 1, January-February 1964, pp. 1-7.

57. _____. Statistical Reliability of Particle-Size Distributions Determined by Microscopic Techniques. Am. Ind. Hyg. Assoc. J., v. 26, No. 1, January-February 1965, pp. 8-16.

58. Couchman, J. C., and H. M. Moseley. Simplified Method for Determining Cascade Impactor Stage Efficiencies. Am. Ind. Hyg. Assoc. J., v. 28, No. 1, January-February 1967, pp. 62-67.

59. Crable, John V. Quantitative Determination of Chrysotile, Amosite, and Crocidolite by X-Ray Diffraction. Am. Ind. Hyg. Assoc. J., v. 27, No. 3, May-June 1966, pp. 293-298.

60. Crable, John V., and Marta J. Knott. Application of X-Ray Diffraction to the Determination of Chrysotile in Bulk or Settled Dust Samples. Am. Ind. Hyg. Assoc. J., v. 27, No. 4, July-August 1966, pp. 383-387.

61. Cunningham, W. Roy. Dust Study Program, Pennsylvania Department of Mines and Mineral Industries. Trans. 49th Nat. Safety Cong., Coal Min. Sessions, v. 7, 1961, pp. 24-28.

62. Dalzell, Robert W. Face Ventilation in Underground Bituminous Coal Mines. Performance Characteristics of Common Jute Line Brattice. BuMines Rept. of Inv. 6725, 1966, 30 pp.

63. _____. Line Brattice Ventilation. Proc. 54th Conv. Mine Inspectors' Inst. America, Richmond, Va., June 15-17, 1964, pp. 78-85.

64. Dannenberg, Joe. No Wonder Detergent Drilling is Making Headway - Its Cost Averages Less Than 20 Cents per Drill Shift. Pit and Quarry, v. 58, November 1965, pp. 129-131.

65. Davies, C. N. Recent Advances in Aerosol Research, a Bibliographical Review. Pergamon Press, New York, 1964, 80 pp.

66. Devens, Willis R. The Role of the Mine Inspector in Dust Control in Anthracite Mines. Proc. Pennsylvania Governor's Conference on Pneumoconiosis (Anthraco-Silicosis), Harrisburg, Pa., Nov. 30-Dec. 2, 1964, pp. 133-135.

67. Dimitroff, A. Z., and A. C. Moschetti. Rock-Dust Disseminator Used in Return Air Currents, Koehler Mine, Kaiser Steel Corp., Koehler, N. Mex. BuMines Inf. Circ. 8253, 1965, 7 pp.

68. Doyle, Henry N. A Study of Chronic Chest Disease in Bituminous Coal Mines. Proc. 53d Conv. Mine Inspectors' Inst. America, Columbus, Ohio, June 17-19, 1963, pp. 113-119.

69. Draper, J. C. Control of Float Dust in Return Airways by Auxiliary Fans. Min. Cong. J., v. 49, No. 6, June 1963, pp. 35-37.

70. Dulaney, Roy L. The Use of Auxiliary Fans. Proc. 54th Conv. Mine Inspectors' Inst. America, Richmond, Va., June 15-17, 1964, pp. 73-78.

71. Eadie, George R. Trickle-Duster Eliminates Hazard of Float Dust. Coal Min. and Processing, v. 4, No. 3, March 1967, pp. 40-43.

72. Edwards, George H. Comparison of X-Ray Diffraction, Chemical (Phosphoric Acid), and Dispersion Staining Methods for the Determination of Quartz in Dust. Am. Ind. Hyg. Assoc. J., v. 26, No. 5, September-October 1965, pp. 532-536.

73. Edwards, Ralph E., Charles H. Powell, and Mildred A. Kendrick. Dust Counting Variability. Am. Ind. Hyg. Assoc. J., v. 27, No. 6, November-December 1966, pp. 546-554.

74. Elkins, J. E., and J. C. Draper. Underground Mining. Min. Cong. J., v. 52, No. 2, February 1966, pp. 59-63.

75. Enterline, Philip E. Mortality Rate Among Coal Miners. Am. J. Pub. Health, v. 54, May 1964, pp. 758-768.

76. Ettinger, Harry J., and Samuel Posner. Evaluation of Particle Sizing and Aerosol Sampling Techniques. Am. Ind. Hyg. Assoc. J., v. 26, No. 1, January-February 1965, pp. 17-25.

77. Flesch, Jerome P., Charles H. Norris, and Albert E. Nugent, Jr. Calibrating Particulate Air Samplers With Monodisperse Aerosols: Application to the Andersen Cascade Impactors. Am. Ind. Hyg. Assoc. J., v. 28, No. 6, November-December 1967, pp. 507-513.

78. Garvey, James R. Summary of Dust Control Activity. Trans. 55th Nat. Safety Cong., Coal Min. Sessions, 1967, pp. 12-15.

79. Glauberman, Harold. The Directional Dependence of Air Samplers. Am. Ind. Hyg. Assoc. J., v. 23, No. 3, May-June 1962, pp. 235-239.

80. Godard, R. R. Dust Abatement Activities Within United States Steel Corporation's Coal Operations. Abs. in Coal Age, v. 72, No. 4, April 1967, p. 112. Full text available for inspection at the Bureau of Mines Health and Safety Research and Testing Center, Pittsburgh, Pa.

81. Goodfellow, Robert D., Jr. Recent Advances in Mining Tools. Min. Cong. J., v. 51, June 1965, pp. 79-81.

82. Gussman, Robert A., and David Gordon. Notes on the Modification and Use of a Cascade Impactor for Sampling in Ducts. Am. Ind. Hyg. Assoc. J., v. 27, No. 3, May-June 1966, pp. 252-255.

83. Hall, Frank E., Richard E. Kupel, and Robert L. Harris, Jr. Particle Settling Times in Ethyl Alcohol-Water Mixtures as Affected by Variables in Impinger Sampling. Am. Ind. Hyg. Assoc. J., v. 26, No. 5, September-October 1965, pp. 537-543.

84. Hammond, H. R. Underground Mining Trends. Min. Cong. J., v. 52, No. 2, February 1966, pp. 52-57.

85. Harper, D. S., and C. O. Carman. Longwall Mining With a German Coal Planer. Pocahontas No. 3 Coalbed, Keystone, W. Va. BuMines Rept. of Inv. 6291, 1963, 18 pp.

86. Harris, E. J. Face Ventilation. Proc. 53d Conv. Mine Inspectors' Inst. America, Columbus, Ohio, June 17-19, 1963, pp. 120-126.

87. Harrison, Walter K., Jr., John S. Nader, and Frank S. Fugman. Constant Flow Regulators for the High-Volume Air Sampler. Am. Ind. Hyg. Assoc. J., v. 21, No. 2, April 1960, pp. 115-120.

88. Hatch, Theodore F. Perspectives in Industrial Hygiene. Arch. Environ. Health, v. 8, No. 3, March 1964, pp. 393-397.

89. Hatch, Theodore F., and Paul Gross. Pulmonary Deposition and Retention of Inhaled Aerosols. Academic Press, New York, 1964, 192 pp.

90. Herde, Roy S. Dust Control on Mine Roads. Min. Cong. J., v. 51, No. 7, July 1965, pp. 90-92.

91. Hite, Mark. Contributions of Electron Microscopy to Occupational Health. Am. Ind. Hyg. Assoc. J., v. 26, No. 4, July-August 1965, pp. 374-379.

92. Howell, Roger J. Dust Study Program by Pennsylvania Department of Mines and Mineral Industries. Proc. 51st Conv. Mine Inspectors' Inst. America, Pittsburgh, Pa., June 19-21, 1961, pp. 89-95.

93. Hyatt, E. C., H. F. Schulte, C. R. Jensen, R. N. Mitchell, and G. H. Ferran. A Study of Two-Stage Air Samplers Designed to Simulate the Upper and Lower Respiratory Tract. 13th Internat. Cong. on Occ. Health, 1960, pp. 486-503.

94. Idaho, Inspector of Mines and Industrial Accident Board. Minimum Safety Standards and Practices for Mining and Mineral Industry, Safety Code 5, July 1, 1963, 89 pp.

95. Irani, R. R., and E. F. Kaelble. Particle-Size Distribution Measurements Below Five Microns. Anal. Chem., v. 33, No. 9, August 1961, pp. 1168-1170.

96. Jacobson, Murray, and T. F. Tomb. Relationship Between Gravimetric Respirable Dust Concentration and Midget Impinger Number Concentration. Am. Ind. Hyg. Assoc. J., v. 28, No. 6, November-December 1967, pp. 554-556.

97. Jones, Don C. Roof Control. Mechanization, v. 25, No. 1, January 1961, pp. 35-39.

98. _____. Roof Control, Part II: Roof Control With Bolts. Mechanization, v. 25, No. 2, February 1961, pp. 52-54.

99. _____. Roof Control, Part III: Bolting Equipment. Mechanization, v. 25, No. 3, March 1961, pp. 47-50.

100. Jones, Thomas E. The Role of the Mine Inspector in Dust Control in Bituminous Coal Mines. Proc. Pennsylvania Governor's Conference on Pneumoconiosis (Anthraco-Silicosis), Harrisburg, Pa., Nov. 30-Dec. 2, 1964, pp. 127-129.

101. Judy, George L. What the Coal Industry is Doing to Control Dust. Trans. 55th Nat. Safety Cong., Coal Min. Sessions, 1967, pp. 6-8.

102. Kaplan, Stuart R., ed. A Guide to Information Sources in Mining, Minerals and Geosciences, v. 2. Interscience Publishers, New York, 1965, 599 pp.

103. Karlovsky, Jerry. Developments in Cutter Heads on Boring-Type Continuous Miners. Abs. in Coal Age, v. 72, No. 12, December 1967, p. 116.

104. Kawenski, Edward M., and Donald W. Mitchell. Rapid and Inexpensive Erection of Stoppings With Rigid Foam. Proc. 76th Ann. Meet. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 13-14, 1962, pp. 80-87.

105. Kawenski, Edward M., Edwin M. Murphy, and R. Ward Stahl. Float Dust Deposits in Return Airways in American Coal Mines. BuMines Inf. Circ. 8150, 1963, 20 pp.

106. Kingery, D. S. Bureau of Mines Research on Mine Safety. Proc. 55th Conv. Mine Inspectors' Inst. America, Sequoyah State Park, Okla. June 7-9, 1965, pp. 163-167.

107. Kuhn, W. E., Headlee Lamprey, and Charles Sheer. Ultrafine Particles. John Wiley & Sons, Inc., New York, 1963, 561 pp.

108. Laing, Robert T. Current Problems Facing the Coal Industry in Pennsylvania. Proc. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 9-10, 1965, pp. 94-99.

109. Laird, Frank, Jr. Practical Dust Control. Min. Cong. J., v. 47, No. 8, August 1961, pp. 54-57.

110. Lee, F. R., and R. L. Evans. Permissible Mine Equipment Approved by the Bureau of Mines During 1953-62. A Supplement to Bulletin 543. BuMines Inf. Circ. 8220, 1964, 39 pp.

111. Levo, Nicholas, Jr. Dust Control in Coal Mines. Trans. 53d Nat. Safety Cong., Coal Min. Sessions, 1965, pp. 11-13.

112. _____. Dust Control on Underground Coal Conveyors. Min. Cong. J., v. 51, No. 12, December 1965, pp. 24-26.

113. Lieben, Jan. Coal Miners Pneumoconiosis in Pennsylvania - 1967. Pres. Coal Workers Pneumoconiosis Symp., May 18, 1967, 13 pp. Available for inspection at the Bureau of Mines Health and Safety Research and Testing Center, Pittsburgh, Pa.

114. _____. Pneumoconiosis. A Review of the Present Situation and the Program for Control of a Very Extensive Health Hazard in Our Commonwealth. Pennsylvania Med., v. 70, No. 12, December 1967, pp. 75-78.

115. Lieben, Jan, and W. Wayne McBride. Pneumoconiosis in Pennsylvania's Bituminous Mining Industry. J. Am. Med. Assoc., v. 183, No. 3, January 1963, pp. 102-150.

116. Lieben, Jan, Eugene Pendergrass, and W. Wayne McBride. Pneumoconiosis Study in Central Pennsylvania Coal Mines. J. Occ. Med., v. 3, No. 11, November 1961, pp. 493-505.

117. Linch, A. L., and M. Corn. The Standard Midget Impinger - Design Improvement and Miniaturization. Am. Ind. Hyg. Assoc. J., v. 26, No. 6, November-December 1965, pp. 601-610.

118. Lingo, Paul C. Methods of Using Auxiliary Fans for Face Ventilation With Continuous Mining Systems. Trans. 49th Nat. Safety Cong., Coal Min. Sessions, v. 7, 1961, pp. 6-10.

119. Lippmann, Morton. A Compact Cascade Impactor for Field Survey Sampling. Am. Ind. Hyg. Assoc. J., v. 22, No. 5, October 1961, pp. 348-353.

120. Lippmann, Morton, Hugo J. DiGiovanni, Samuel Cravitt, and Pedro Lilienfeld. Lightweight, High-Volume Electrostatic Precipitator Survey Sampler. Am. Ind. Hyg. Assoc. J., v. 26, No. 5, September-October 1965, pp. 485-489.

121. Lippmann, M., and W. B. Harris. Size-Selective Samplers for Estimating "Respirable" Dust Concentrations. Health Physics, v. 8, No. 2, April 1962, pp. 155-163.

122. Maize, Earl R. The State of the Art of Ventilation, Part A: Coal Faces. Proc. 55th Conv. Mine Inspectors' Inst. America, Sequoyah State Park, Okla., June 7-9, 1965, pp. 130-135.

123. Malmgren, Carl. Dry Percussion Drilling With Detergent Mists. Min. Cong. J., v. 51, No. 1, January 1965, p. 62.

124. McBride, W. Wayne, Eugene Pendergrass, and Jan Lieben. Pneumoconiosis Study of Western Pennsylvania Bituminous-Coal Miners. J. Occ. Med., v. 5, No. 8, August 1963, pp. 376-388.

125. _____. Pneumoconiosis Study of Pennsylvania Anthracite Miners. J. Occ. Med., v. 8, No. 7, July 1966, pp. 365-376.

126. McKenry, R. J. The Development and Application of the U-40 Series (Kennametal's Plumb-Bob Tools). Proc. Coal Min. Inst. America, 1965, pp. 130-138.

127. McMillan, Earl R. Hydraulic Jet Mining Shows Potential as a New Tool for Coal Men. Min. Eng., v. 14, No. 6, June 1962, pp. 41-45.

128. McPhillamey, Robert H. The New Federal Safety Legislation and Your Operations. Trans. 55th Nat. Safety Cong., Min. Sessions, v. 16, 1967, pp. 17-23.

129. Memmott, Frank C. The New Federal Coal-Mine Safety Law. Abs. in Coal Age, v. 71, No. 12, December 1966, p. 107.

130. Mercer, T. T. The Interpretation of Cascade Impactor Data. Am. Ind. Hyg. Assoc. J., v. 26, No. 3, May-June 1965, pp. 236-241.

131. Mercer, W. B. Calibration of Coulter Counter for Particles About 1 Micron in Diameter. Rev. Sci. Instr., v. 37, No. 11, November 1966, pp. 1515-1520.

132. Merritts, W. M. Degasification of Coal Mines. Proc. 54th Conv. Mine Inspectors' Inst. America, Richmond, Va., June 15-17, 1964, pp. 57-66.

133. Merritts, W. M., W. N. Poundstone, and B. A. Light. Removing Methane (Degasification) From the Pittsburgh Coalbed in Northern West Virginia. BuMines Rept. of Inv. 5977, 1962, 39 pp.

134. Merritts, W. M., C. R. Waine, L. P. Mokwa, and M. J. Ackerman. Removing Methane (Degasification) From the Pocahontas No. 4 Coal Bed in Southern West Virginia. BuMines Rept. of Inv. 6326, 1963, 39 pp.

135. Metzger, Charles L. Dust Suppression and Drilling With Foaming Agents. Pit and Quarry, v. 60, No. 3, March 1967, pp. 132-138.

136. Michigan, 74th Legislature. Public Acts of 1967, Act 264, approved July 19, 1967.

137. Michigan Department of Health. Protecting Health in Mines and Tunnels. Michigan's Occ. Health, v. 6, No. 3, Spring 1961, pp. 1-8.

138. Mitchell, D. W., W. Ward Stahl, and E. M. Kawenski. Continuous Rock Dusting to Reduce the Float Dust Explosion Hazard. Proc. 54th Conv. Mine Inspectors' Inst. America, Richmond, Va., June 15-17, 1964, pp. 94-100.

139. Montana. Minimum Safety Standards for Mining, Quarrying, Milling, and Smeltering Operations in Montana. August 1961, 77 pp.

140. Morrow, Paul E. Evaluation of Inhalation Hazards Based Upon the Respirable Dust Concept and the Philosophy and Application of Selective Sampling. Am. Ind. Hyg. Assoc. J., v. 25, No. 3, May-June 1964, pp. 213-236.

141. Morton, H. C. Try Water Infusion. Coal Min. and Processing, v. 4, No. 8, August 1967, pp. 48-49.

142. Murphy, E. Lewis. Operating Experience With Boring Machines at Humphrey No. 7 Mine. Proc. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 12-13, 1963, pp. 85-91.

143. Myers, E. D. Further Developments in the Millipore Filter Technique for Counting Coal Dust. Tennessee Ind. Hyg. News, v. 18, No. 1, Winter 1961, pp. 1-4.

144. Nagy, John. Float Dust Hazard in Coal Mines. Proc. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 9-10, 1965, pp. 111-120.

145. Nagy, John, and Donald W. Mitchell. Hazards From Float Coal Dust and How They can Be Minimized. Proc. 51st Conv. Mine Inspectors' Inst. America, Pittsburgh, Pa., June 19-21, 1961, pp. 95-101.

146. Nagy, John, Donald W. Mitchell, and Edward M. Kawenski. Float Coal Hazard in Mines: A Progress Report. BuMines Rept. of Inv. 6581, 1965, 15 pp.

147. Nasiatka, Thomas M., and Frank Badda. Hydraulic Coal Mining Research, Tests in a Steeply Pitching Coalbed, Roslyn, Washington. BuMines Rept. of Inv. 6276, 1963, 16 pp.

148. Nevada State Inspector of Mines. Nevada State Mining Laws, 1966 Edition, compiled by Mervin J. Gallager. July 1966, 116 pp.

149. New Mexico, State Inspector of Mines. New Mexico Mine Safety Code for All Mines, Including Open-Cut and Open-Pit, compiled by William H. Hays. 1965, 105 pp.

150. Oklahoma State Legislature, 30th Regular Session. Enrolled Senate Bill No. 166, signed June 23, 1965.

151. Owings, C. W. Dust Control in Mining, Tunneling, and Quarrying in the United States. BuMines Inf. Circ. 7760, 1956, 38 pp.

152. Palmer, Archie M., and Anthony T. Kruzas, eds. Research Centers Directory. Gale Research Co., Detroit, Mich., 1965, 2d ed., 63 pp.

153. Palowitch, E. R., and W. T. Malenka. Hydraulic Mining Research - A Progress Report. Min. Cong. J., v. 50, No. 9, September 1964, pp. 66-73.

154. Parisi, C. William. Conventional Mining - Coal Dust Abatement. Abs. in Coal Age, v. 72, No. 4, April 1967, p. 111.

155. _____. Dust Abatement at Pittsburgh Coal Co. Abs. in Coal Age, v. 72, No. 6, June 1967, p. 103.

156. Patterson, C. H. Progress in Ventilating Continuous Mining Sections. Min. Cong. J., v. 47, No. 3, March 1961, pp. 29-32.

157. Pennsylvania Department of Health. New Trend in Dust Sampling. Occ. Health News and Views, v. 4, No. 4, Fall 1966, 1 p.

158. Pennsylvania Department of Health, Division of Air Pollution Control. Standard Method for Particle-Size Determinations, Sept. 1, 1966, 9 pp.

159. Pennsylvania Department of Health, Department of Labor and Industry, and Department of Mines and Mineral Industries. Proc. Pennsylvania Governor's Conference on Pneumoconiosis (Anthraco-Silicosis), Harrisburg, Pa., Nov. 30-Dec. 2, 1964, 259 pp.

160. Pennsylvania Department of Mines and Mineral Industries. Bituminous Coal Mining Laws of Pennsylvania for Underground Mines, 1961, 231 pp.

161. _____. Bituminous Coal Mining Laws of Pennsylvania for Strip Mines, Jan. 1, 1962, 55 pp.

162. Posner, Samuel, and Eugene Miner. A New Method of Preparing Carbon-Coated Copper Electron Microscope Grids. Am. Ind. Hyg. Assoc. J., v. 24, No. 2, March-April 1963, pp. 188-191.

163. Power. Power Special Report. No More Coal-Dust Problem for Georgia Power. V. 105, No. 7, July 1961, pp. 184-185.

164. Princen, L. H., and W. F. Kwolek. Coincidence Corrections for Particle-Size Determinations With the Coulter Counter. Rev. Sci. Instr., v. 36, No. 5, May 1965, pp. 646-653.

165. Public Health Service, U.S. Department of Health, Education, and Welfare. Governors' Conference on Health Hazards in Uranium Mines. Public Health Service Pub. 843, 1961, 13 pp.

166. _____. Occupational Characteristics of Disabled Workers, by Disabling Conditions. Public Health Service Pub. 1531, 1967, 307 pp.

167. _____. Silicosis in the Metal Mining Industry - A Revaluation - 1958-1961. Public Health Service Pub. 1076, 1963, 238 pp.

168. Rachunis, William, Arthur A. Sinicrope, and James A.Moore. Safety Practices in Shaft Sinking and Tunneling: West Delaware Aqueduct. BuMines Inf. Circ. 8114, 1962, 35 pp.

169. Roach, S. A., E. J. Baier, H. E. Ayer, and R. L. Harris. Testing Compliance With Threshold Limit Values for Respirable Dusts. Am. Ind. Hyg. Assoc. J., v. 28, No. 6, November-December 1967, pp. 543-553.

170. Rock Products. Rock Products Special Report. Chemicals Quell Dust. V. 65, No. 8, August 1962, pp. 92, 95-96.

171. Saltzman, Robert D. A Review of Various Aspects of the Float Dust Problem. Trans. 53d Nat. Safety Cong., Coal Min. Sessions, 1965, pp. 13-18.

172. _____. What's New is Dust Control. Min. Cong. J., v. 51, No. 8, August 1965, pp. 54-58.

173. Sanderson, H. P., A. F. W. Cole, Morris Katz, and S. Baburik. An Improved High-Volume Air Sampler and a Weighable Support for Fibre Glass Filters. Am. Ind. Hyg. Assoc. J., v. 24, No. 4, July-August 1963, pp. 404-410.

174. Schiager, K. J., T. M. Allen, S. B. Gerber, G. E. Kinsella, F. J. Krupka, and D. W. Reilly. Improved Membrane-Filter Air-Sampling Methods for Environmental Control. Health Physics, v. 7, No. 314, 1962, pp. 185-190.

175. Schlick, Donald P., and Robert W. Dalzell. Ventilation of Continuous-Miner Places in Coal Mines. BuMines Inf. Circ. 8161, 1963, 18 pp.

176. Schutz, Robert H. Respirators: Emergency and Nonemergency. Pres. at Safety Symp., Am. Inst. Chem. Eng., Boston, Mass., Dec. 8, 1964, 20 pp. Available for inspection at the Bureau of Mines Health and Safety Research and Testing Center, Pittsburgh, Pa.

177. Sheinbaum, Milton. Comparative Concentration of Silica in Parent Material and in Airborne Particulate Matter. Am. Ind. Hyg. Assoc. J., v. 22, No. 4, August 1961, pp. 313-317.

178. Shoub, Earle P. Dust Measurement and Standards. Trans. 53d Nat. Safety Cong., Coal Min. Sessions, 1965, pp. 18-26.

179. Shupe, D. B. Mechanical Coal Mining. Min. Cong. J., v. 53, No. 2, February 1967, pp. 156-159.

180. Smith, Earl P. Shaft Raising in Alabama. Abs. in Coal Age, v. 69, No. 6, June 1964, p. 101.

181. South Dakota Inspector of Mines. South Dakota Mine Safety Code for All Mines Including Quarries and Open-Pit, compiled by Philip Graves, 1967, 20 pp.

182. Talvitie, N. A. Determination of Free Silica: Gravimetric and Spectrophotometric Procedures Applicable to Air-Borne and Settled Dust. Am. Ind. Hyg. Assoc. J., v. 25, No. 2, March-April 1964, pp. 169-178.

183. Talvitie, N. A., and Lial W. Brewer. X-Ray Diffraction Analysis of Industrial Dust. Am. Ind. Hyg. Assoc. J., v. 23, No. 3, May-June 1962, pp. 214-221.

184. Tobie, Raymond L. Underground Mining. Min. Cong. J., v. 53, No. 2, February 1967, pp. 143-151.

185. Todhunter, John S. Face Ventilation and Dust Control. Min. Cong. J., v. 48, No. 1, January 1962, pp. 38-40, 48.

186. Trasko, Victoria M. Socio-Economic Aspects of the Pneumoconioses. Arch. Environ. Health, v. 9, No. 4, October 1964, pp. 521-528.

187. U.S.A. Standards Institute. Radiation Protection in Uranium Mines and Mills (N7.1-1960), New York, 1960, 29 pp.

188. U.S. Congress. Radiation Exposure of Uranium Miners. Hearings Before the Subcommittee on Research, Development, and Radiation of Joint Committee on Atomic Energy, pt. 1-2, 90th Cong. 1st Sess., 1967, 1373 pp.

189. U.S. Statutes at Large. Federal Coal Mine Safety Act. Amendments of 1965. Public Law 89-376, Mar. 26, 1966, 80 Stat. 84.

190. _____. Federal Metal and Nonmetallic Mine Safety Act. Public Law 89-577, Sept. 16, 1966, 80 Stat. 772.

191. Utah Industrial Commission. General Safety Orders Covering Metal and Nonmetal Mines, Mills, Smelters, Tunnels, Quarries, Gravel Pits, Etc., In the State of Utah. July 1, 1963, 97 pp.

192. _____. General Safety Orders Utah Coal Mines. Jan. 1, 1967, 137 pp.

193. Vines, Robert L. Dust Control. Proc. Coal Min. Inst. America, Pittsburgh, Pa., Dec. 14-15, 1967, pp. 101-109.

194. Virginia Department of Labor and Industry. Mining Laws of Virginia, 1966, 167 pp.

195. Wallace, J. J. Bureau of Mines Research in Hydraulic Coal Mining. Min. Cong. J., v. 47, No. 1, January 1961, pp. 52-54.

196. Wallace, J. J., G. C. Price, and M. J. Ackerman. Hydraulic Coal Mining Research: Equipment and Preliminary Tests. BuMines Rept. of Inv. 5915, 1961, 25 pp.

197. Warren, John W. The State of the Art of Ventilation, Part B: Metal Mines. Proc. 55th Conv. Mine Inspectors' Inst. America, Sequoyah State Park, Okla., June 8, 1965, pp. 135-162.

198. Westfield, James. Safety in Mining, 1964. Min. Cong. J., v. 51, No. 2, February 1965, pp. 48-55.

199. West Virginia, Department of Mines. Mining Laws of West Virginia 1967, p. 199.

200. Wyoming, Office of State Inspector of Mines. Non-Coal Mining Laws Including Safety Rules and Regulations, January 1966, 62 pp.

201. Young, W. H., and J. J. Gallagher. Coal - Bituminous and Lignite. BuMines Minerals Yearbook, 1965 (pub. 1967), v. 2, p. 81.

202. Zullo, P. Interpretation of Environmental Data Collected by the Department of Mines and Mineral Industries. Proc. Pennsylvania Governor's Conference on Pneumoconiosis (Anthraco-Silicosis), Harrisburg, Pa., Nov. 30-Dec. 2, 1964, pp. 137-138.

203. Zullo, Philip, and Edward Digon. Light-Field Microscope Versus Microprojector in Determining Coal Dust Concentrations. Am. Ind. Hyg. Assoc. J., v. 28, No. 3, May-June 1967, pp. 238-242.

IC bureau of mines information circular 8408

IMPACT OF PETROLEUM DEVELOPMENT IN THE GULF OF MEXICO

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

1969

IMPACT OF PETROLEUM DEVELOPMENT IN THE GULF OF MEXICO

By L. K. Weaver, C. J. Jirik, and H. F. Pierce

* * * * * * * * * * * information circular 8408

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

Weaver, Lewis K

Impact of petroleum development in the Gulf of Mexico, by L. K. Weaver, C. J. Jirik, and H. F. Pierce. [Washington] U. S. Dept. of the Interior, Bureau of Mines [1969]

58 p. illus., tables. (U. S. Bureau of Mines. Information circular 8408)

Includes bibliography.

1. Petroleum in submerged lands. 2. Petroleum industry and trade—Mexico, Gulf of. I. Jirik, Charles J., jt. auth. II. Pierce, H. F., jt. auth. III. Title. (Series)

TN23.U71 no. 8408 622.06173

U. S. Dept. of the Int. Library

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price 70 cents

ILLUSTRATIONS

TABLES

IMPACT OF PETROLEUM DEVELOPMENT IN THE GULF OF MEXICO

by

L. K. Weaver,[1] C. J. Jirik,[1] and H. F. Pierce[1]

ABSTRACT

Bureau of Mines investigated the progressive impact that petroleum (crude oil and condensate) operations in the Gulf of Mexico have had on onshore operations and the expected effect of increasing activities in this area on future petroleum supplies from domestic sources. The data analyzed include capital expenditures, number of wells drilled, success ratio for exploratory wells, daily production per completion, annual producing rates, and oil reserves. The report compares offshore and onshore data and ascertains trends in petroleum industry operations.

Observed data and trends indicate that in the near future Gulf of Mexico development and production will continue to increase relative to total U.S. petroleum activity. By 1975 annual oil and condensate production from the Gulf of Mexico is expected to be in the range of 750 million bbl to 1,150 million bbl, and account for approximately 20 to 30 pct of the estimated total domestic production.

INTRODUCTION

Because of an apparent decreasing reserve-to-production ratio and declining exploration activity onshore, a current evaluation of petroleum supply potential in the offshore areas of the United States is needed to anticipate the possible magnitude of this new supply and its replacement or displacement of onshore production. This work is part of the Bureau of Mines' overall program of assessing the Nation's petroleum supplies. The purpose of this study is to provide basic and interpretive data for aiding Government officials in making decisions relative to future development of petroleum resources in Federal offshore areas.[2]

---

[1]Petroleum engineer, Dallas Office of Mineral Resources, Bureau of Mines, Dallas, Tex.

[2]Only data for the Gulf of Mexico are analyzed here because, to 1967, development in other offshore areas adjacent to California and Alaska has been in waters chiefly under State jurisdiction. However, oil and gas production data for these areas are included in appendix A, because of the importance of petroleum development in offshore areas owned by the States of California and Alaska.

After ownership and jurisdiction of the natural resources of the seabed of the Outer Continental Shelf (OCS) were defined by the Submerged Lands Act in May 1953 and the Outer Continental Shelf Lands Act in August 1953, leasing and development in the Gulf of Mexico accelerated. There was a shift in petroleum activity from onshore United States to offshore. Since 1956 there has been a trend to smaller total expenditures for drilling and equipping wells in the United States, but the percentage of the total spent offshore has increased from about 7 pct in 1956 to 17 pct in 1965 (2).[3] Crude oil and condensate production from the Gulf of Mexico has increased from less than 1 pct of the total domestic production in 1954 to about 8 pct in 1966. Gulf of Mexico production accounted for about 30 pct of the increase in total domestic production during this period. Approximately 50 pct of the cumulative increase in total U.S. liquid hydrocarbon reserves (about 5 billion bbl) from 1955 through 1966 was from offshore Louisiana (14). Water depths of producing tracts have increased progressively to about 350 ft (South Pass Block 62 field) and distances from shore have increased to about 70 miles (Vermilion Block 245 field).

Time lags between leasing, drilling, and significant production operations, attributable to different reasons, make forecasts of offshore petroleum supplies uncertain: for example, periods of nearly 5 years between lease date and discovery date of a field and 10 years between discovery date and the date of first significant commercial production. Despite these variations, however, a definite trend in Gulf of Mexico oil and condensate production has been established (1956-66).

Increased petroleum production from the Gulf of Mexico has changed the traditional supply patterns by displacement of possible onshore production, principally in Texas and Louisiana, which have significant shut-in productive capacity. Oil industry activities, including leasing, geophysical exploration, and drilling, along with the reserves developed as a result of these activities, were considered in estimating future sources of supply. Another factor considered in estimating probable future production is the rate of technology increase necessary to advance into deeper water. The design of drilling and production platforms that can withstand violent weather conditions, underwater completion methods, and the installation and operation of large-diameter pipelines on the sea floor are challenges that are being met by increased technology. On the basis of past offshore experience and opinions of industry management, the depth of water in which drilling and production operations may be performed will be limited by economics rather than technology.

A recent study summarized the relevant data on leasing, drilling, and production operations related to oil and gas in the offshore areas contiguous to the United States from 1953 through 1965, and includes those areas primarily under Federal administration.[4] This report presents additional information

---

[3]Underlined numbers in parentheses refer to items in the list of references preceding the appendixes.

[4]U.S. Department of the Interior. Petroleum Production, Drilling and Leasing on the Outer Continental Shelf. May 1966, 20 pp.

and an analysis of the leasing, drilling, and production operations to forecast the source and availability of future supplies of petroleum.

ACKNOWLEDGMENTS

The authors gratefully acknowledge the cooperation and assistance of the U.S. Geological Survey, U.S. Bureau of Land Management, and Louisiana Department of Conservation. Special acknowledgment is due Robert F. Evans, Oil and Gas Supervisor, and staff, Gulf Coast Region of the U.S. Geological Survey, New Orleans, La.; John L. Rankin, Manager of Land Office, and staff, U.S. Bureau of Land Management, New Orleans, La.; and Thomas M. Winfiele, Chief Engineer, and staff, Louisiana Department of Conservation, Baton Rouge, La.

The data and assistance furnished by Calvin H. Riggs, Petroleum Engineer, Bureau of Mines, San Francisco Office of Mineral Resources, and the data furnished by Donald Blasko, Petroleum Engineer, Bureau of Mines, Alaska Office of Mineral Resources, are appreciated.

HISTORY AND IMPACT OF OFFSHORE DEVELOPMENT

The first oil drilled (March 1938) in the open, unprotected water of the Gulf of Mexico was in the area which became known as the Creole field, about 1½ miles from the coastline of Louisiana. Significant development of offshore hydrocarbon deposits, however, did not commence until November 1947 when the Ship Shoal Block 32 field was found about 12 miles from the Louisiana coastline. The first discovery offshore Texas, made in October 1949 on State Lease 245, is still listed as a shut-in gas-condensate well. Widespread development of the hydrocarbon resources in the Gulf of Mexico did not begin until after the Submerged Lands Act and the Outer Continental Shelf Lands Act were passed in 1953. In spite of the costly and difficult problems of operating offshore, such as water depth, adverse weather, and long distances from shore, there has been a rapid movement to offshore provinces. Two reasons for the shift to the Gulf of Mexico are the success ratios, presented in figure 1, and the reserves found (14). Except for 1962, the success ratio for exploratory wells drilled offshore (1) has been higher than the onshore U.S. ratio. From 1953 to 1967, the average success ratio for exploratory wells drilled in the Gulf of Mexico was 26 pct, compared with a ratio for onshore United States of about 18 pct.

From 1955 through 1966, the cumulative production of crude oil and condensate from offshore Louisiana was approximately 1.3 billion bbl. Simultaneously, there was a 2.35-billion-bbl cumulative increase in the liquid hydrocarbon reserve, which amounted to about 50 pct of the total U.S. increase.

In 1967 about 47 pct of all active mobile offshore rigs in the world and 57 pct of all fixed-platform rigs were operating in the Gulf of Mexico (3). Domestic capital expenditures (fig. 2) (7) remained around $6 billion per year from 1956 through 1965 and the amount spent for drilling and production ranged generally from 50 to 60 pct of this amount.[5] The yearly amounts spent on

[5]All money data have been converted to constant dollars using price deflators (1958 = 100) for the gross national product.

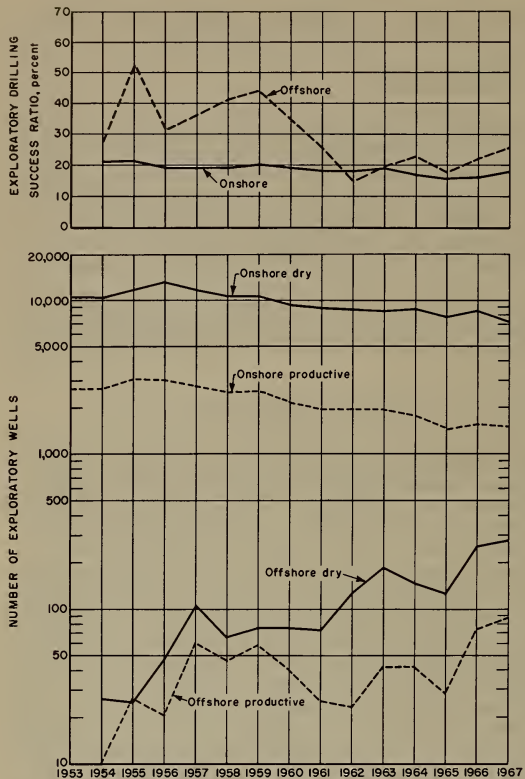


FIGURE 1. - Exploratory Wells Drilled Offshore and Onshore, and a Comparison of the Offshore Success Ratio With the Onshore U.S. Ratio, 1953-67.

completing oil and gas wells also are shown in figure 2. Generally, since 1956 industry has trended to smaller annual amounts spent completing oil and gas wells (2), but the percentage of this amount spent offshore has increased steadily from less than 1.0 pct of the total in 1953 to about 17.0 pct in 1965. Capital expenditure categories include drilling and production, refining, petrochemicals, marketing, natural gas pipelines, crude products pipelines, other transportation, and miscellaneous. Completion expenditures include all amounts for platforms, drilling costs, and the cost for casing, tubing, and wellhead fittings, and do not include the cost of artificial lift equipment or any lease facilities.

The rotary rig count for the United States (8) has declined steadily from 2,687 active rotary rigs in 1955 to 1,135 in July 1967. Over 240 rotary rigs were liquidated during 1967, the fifth consecutive year that over 200 rigs (all onshore) had been liquidated by various drilling companies. While the number of land rigs continues to decrease, that of offshore rigs increased. After the passage of the Submerged Lands Act in 1953, several new companies were incorporated specifically to engage in offshore drilling, and other established companies acquired offshore drilling equipment. For example, the 74 active units in the Gulf of Mexico in 1960 had increased to 97 by 1967 (6) (table 1). While this increase is not comparable numerically with the large decrease in land rigs, it does represent a substantial capital investment: An offshore drilling unit can cost as much as 10 times that of a comparable land unit.

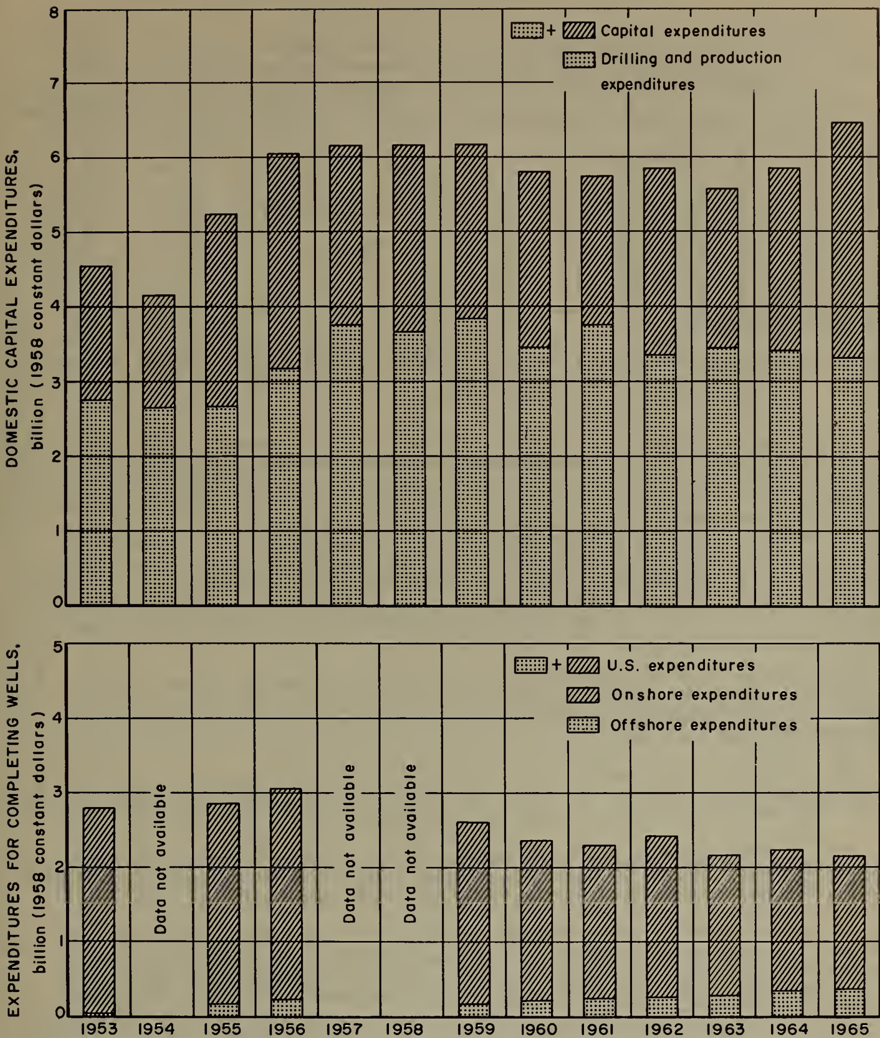


FIGURE 2. - Domestic Capital Expenditures and Expenditures for Completing Wells, 1953-65.

TABLE 1. - Total U.S. onshore and Gulf of Mexico offshore rig count, July 1959 to July 1967

Date	Number of offshore mobile rigs, Maximum water depth, feet: 0-99	100-149	150-199	200-249	250-300	Number of offshore floating units	Number of offshore drilling tenders	Total number of offshore rigs	Total number of U.S. onshore rotary rigs
7/1/59	31	10	-	1	-	-	(1/)	(1/)	1,923
12/31/59	31	10	-	1	-	-	(1/)	(1/)	2,074
12/31/60	31	9	-	-	-	-	34	74	1,746
12/31/61	27	9	2	-	4	-	(1/)	(1/)	1,763
12/31/62	31	9	2	-	2	5	28	77	1,637
12/31/63	30	10	2	-	4	6	(1/)	(1/)	1,501
12/31/64	30	8	3	-	4	6	42	93	1,502
12/31/65	31	4	7	2	6	8	47	105	1,388
12/31/66	31	5	11	2	7	8	29	93	1,270
7/1/67	31	6	13	2	7	9	29	97	1,135

1/ Data not available.

Sources: Louisiana Offshore Oil Scouts Association. Status of the Louisiana Offshore Oil Industry--Statistical Review of Events, 1959-67. The Oil and Gas Journal. Annual Review--Forecast Issue, 1959-67.

The progressive impact that offshore activity has had on onshore geophysical exploration, drilling, and crude oil and condensate production is shown in figure 3. In this report a well is defined as a hole drilled for the purpose of establishing production (oil and gas and dry). A well may have one or more separate completions, each for the purpose of producing hydrocarbons from a separate reservoir to the surface. During 1956, the record year for the number of wells drilled in the United States, over 57,500 onshore wells, totaling nearly 229 million ft, were drilled. In 1966 the number of onshore wells had decreased to approximately 35,850 with a total footage of 150 million ft. In contrast, in 1955 over 400 wells were drilled offshore in the Gulf of Mexico with a total footage just under 4 million ft. In 1966 the number of offshore wells drilled had increased to over 1,160 with footage totaling over 11 million ft.

Exploratory wells are those that are drilled in an attempt to find new and as yet undisclosed hydrocarbon deposits or that are searching for long extensions of fields already partially developed. To make a comparison between onshore and offshore, the following data are available:

1. In 1957, of the onshore wells drilled, 14,540 were exploratory wells having a total footage of approximately 67 million ft; in addition, 165 exploratory wells totaling over 1.8 million ft were drilled in the Gulf of Mexico.

2. By 1967 the number of onshore exploratory wells drilled in the United States had decreased to 8,685 and the footage had decreased to 45 million ft. In 1967, in the Gulf of Mexico, 374 exploratory wells totaling over 4 million ft were drilled.

3. Onshore crude oil and condensate production had an average growth rate of 1.5 pct per year from 1954 through 1966 while the average offshore rate was 26 pct per year. Approximately 30 pct of the increase in domestic production (onshore plus offshore) in this period was from wells in the Gulf of Mexico. The impact of crude oil and condensate production from the Federal area in the Gulf of Mexico is shown in table 2. This production has increased from about 0.1 pct of the U.S. total in 1954 to over 6.0 pct in 1966. In the same time interval Texas production decreased from 42.1 to 34.9 pct of the U.S. total and Louisiana production (including zone 1 and inside the Chapman line offshore) increased from 10.5 to 16.1 pct of the U.S. total.

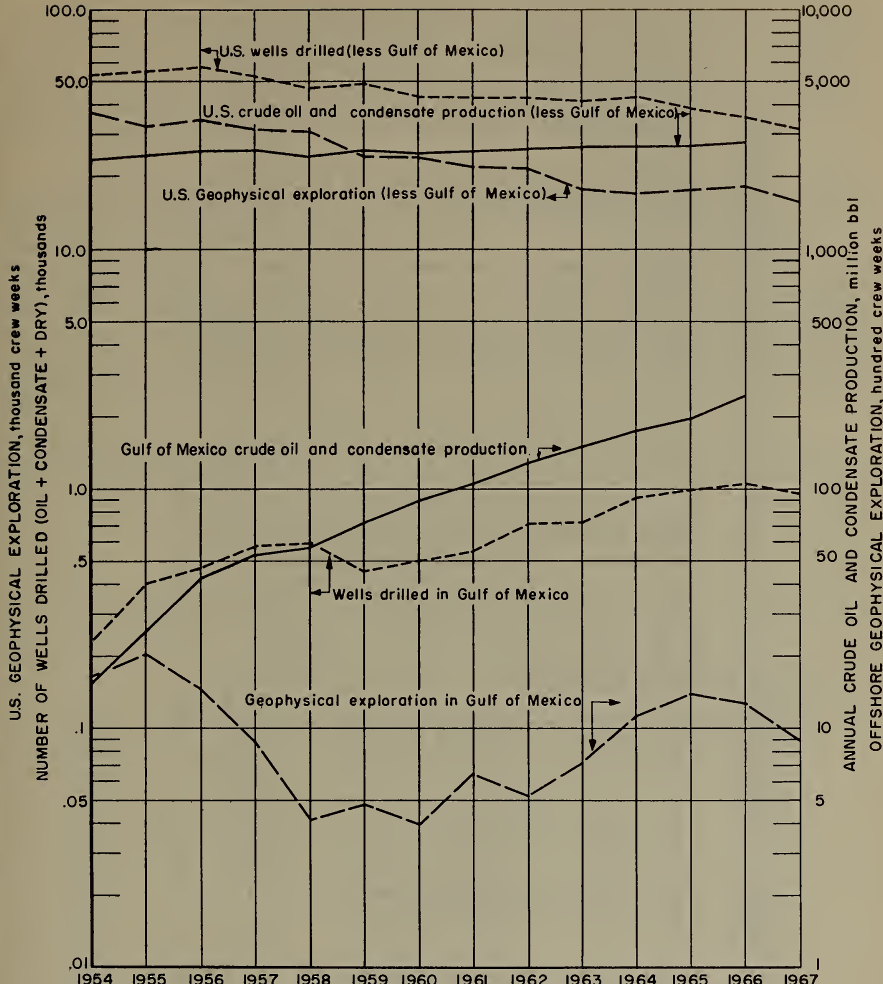


FIGURE 3. - Geophysical Exploration, Drilling, and Crude Oil and Condensate Production Histories of Onshore United States and Gulf of Mexico, 1954-66.

TABLE 2. - Domestic crude oil and condensate production; by State, percent

State	1966	1965	1964	1963	1962	1961	1960	1959	1958	1957	1956	1955	1954
Texas.........	34.9	35.1	35.5	35.5	35.2	35.8	36.0	37.8	38.4	41.0	42.3	42.4	42.1
Offshore1/.....	6.2	5.2	4.4	3.7	3.1	2.4	1.8	1.3	.9	.6	.4	.3	.1
Louisiana2/ ...	16.1	15.7	15.3	15.0	14.7	13.8	13.8	12.8	11.9	12.0	11.0	10.6	10.5
California....	11.4	11.1	10.8	10.9	11.1	11.4	11.8	12.0	12.8	13.0	13.4	14.3	15.4
Oklahoma......	7.4	7.1	7.3	7.3	7.6	7.4	7.5	7.7	8.2	8.2	8.2	8.2	8.0
Wyoming.......	4.4	4.9	5.0	5.2	5.1	5.4	5.2	4.9	4.7	4.2	4.0	4.0	4.0
New Mexico....	4.1	4.1	4.1	4.0	4.1	4.3	4.2	4.1	4.0	3.6	3.4	4.9	5.2
Kansas........	3.4	3.7	3.8	4.0	4.2	4.3	4.4	4.6	4.9	4.7	4.7	3.3	3.2
Illinois......	2.0	2.3	2.5	2.7	2.9	2.9	3.0	3.0	3.3	2.9	3.1	3.3	2.9
Mississippi...	1.8	1.9	2.0	2.1	2.1	2.1	2.0	1.9	1.6	1.5	1.6	1.5	1.5
Colorado......	1.1	1.2	1.2	1.4	1.6	1.8	1.9	1.8	2.0	2.1	2.2	2.1	2.0
Montana.......	1.2	1.2	1.1	1.1	1.2	1.1	1.2	1.2	1.1	1.0	.8	.6	.6
Arkansas......	.8	.9	1.0	1.0	1.0	1.2	1.2	1.0	1.2	1.2	1.1	1.1	1.3
Kentucky......	.6	.7	.7	.7	.7	.7	.8	1.1	.7	.7	.7	.6	.6
Michigan......	.5	.5	.6	.6	.6	.7	.6	.4	.4	.4	.4	.5	.5
Other States..	4.1	4.4	4.7	4.8	4.8	4.7	4.6	4.4	3.9	2.9	2.7	2.3	2.1
Total....	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

1/ Includes all production from zone 2, 3, and 4 offshore Louisiana, and seaward of the 3-league line offshore Texas.

2/ Includes all production from zone 1 and Inside Chapman Line offshore Louisiana.

Table 3 shows the interstate refinery receipts of domestic crude from Louisiana to Texas and Mississippi, and the receipts from all States to Texas. Nearly all of the amount shown going from Louisiana to Mississippi is offshore crude. A 20-in line from Ostrica, La., to Pascagoula, Miss., moves offshore crude oil to the 105,000-bbl-per-stream-day capacity refinery completed in 1963. Feedstock for an ammonia plant completed in 1967 at the Pascagoula complex is supplied by a 12-in gas line from offshore Louisiana.

In 1966 approximately 85 pct of the interstate receipts from all States to Texas was from Louisiana, and nearly all of the Louisiana crude was from south and offshore Louisiana. A large percentage of the interstate receipts to Texas from Louisiana is through a 22-in line carrying south and offshore Louisiana crude oil. Most of the interstate crude oil moved to Texas by barge and tanker (shown in table 3) is from south and offshore Louisiana (a breakdown is not available). The destination of offshore crude oil and condensate is flexible and changes as the demand changes. In the future a major portion of the offshore crude oil now moved by tanker and barge to Texas probably will be diverted to the Great Lakes area in the new 40-in crude oil line (Capline) from St. James, La., to Patoka, Ill.

Pipelines from south and offshore Louisiana also move crude oil to refinery complexes in the Lake Charles, Baton Rouge, and New Orleans areas.

TABLE 3. - Refinery receipts of domestic crude, thousand bbl

Year	Interstate receipts				
	From Louisiana		From all States to Texas		
	To Mississippi 1/	To Texas	Pipeline	Tank car and truck	Tanker and barge
1966....	45,121	209,915	130,490	49	122,886
1965....	42,415	186,078	123,257	-	105,779
1964....	38,657	171,482	125,312	1	89,865
1963....	10,764	168,499	129,649	12	91,988
1962....	295	151,675	134,841	13	76,609
1961....	311	123,660	130,637	12	59,572
1960....	354	124,507	120,484	12	64,789
1959....	319	98,875	119,748	15	44,008
1958....	239	85,009	105,794	-	55,699
1957....	126	71,253	96,947	-	40,170
1956....	-	63,230	96,162	21	41,053
1955....	232	56,826	94,430	-	33,557
1954....	-	61,087	84,800	25	30,877

1/ Prior to 1963 Alabama and Mississippi data were combined.

A study of the undeveloped acreage under lease held by the oil industry also shows a movement to the Gulf of Mexico. Onshore holdings have decreased steadily from about 400 million acres in 1960 to about 300 million acres by January 1, 1968. In this time interval, the offshore acreage had increased from a minor amount to about 1 million acres.

Shipyards have ever-increasing orders for offshore mobile and floating rig units, pipe-laying barges, and all types of equipment to transport labor, material, and petroleum to and from offshore areas. The Petroleum Equipment Suppliers Association (4) reported that by 1966 over 20 pct of their equipment and service sales was for offshore operations. Less than 10 years ago the offshore segment of their business amounted to less than 10 pct.

STATUS OF OWNERSHIP OF OFFSHORE RESOURCES

The controversy over ownership of the natural resources in the submerged lands seaward of State boundaries began in the 1920's. At that time the State of California issued oil and gas leases on certain submerged lands in the Santa Barbara Channel. Subsequent to development of oil production offshore California, the Federal Government received applications for oil and gas rights under the Mineral Leasing Act of 1920. Starting in 1937, unsuccessful attempts were made to pass legislation defining the State and Federal rights in submerged lands. In September 1945 the President issued proclamation No. 2667 stating the Federal Government's jurisdiction and control of the natural resources of the subsoil and seabed of the Continental Shelf. Executive Order No. 9633, issued simultaneously, placed the natural resources of the Continental Shelf under the administrative jurisdiction of the Secretary of the Interior. On June 23, 1947, the U.S. Supreme Court ruled against the State of California holding that California was not the owner of the 3-mile zone of submerged lands adjacent to its coast, and that the Federal Government rather than the State had paramount rights in the submerged lands of the open sea. This decision (332 U.S. 19) meant that the Federal Government owned the resources, including hydrocarbons.

On June 5, 1950, the Supreme Court ruled to the same effect on submerged lands off Texas (339 U.S. 707) and Louisiana (339 U.S. 699).

Following these Supreme Court decisions, the 83d Congress passed H.R. 4198 (identified as the Submerged Lands Act), signed into law as Public Law 31 by the President on May 22, 1953. The purpose of the Act is described in its title as follows:

> To confirm and establish the titles of the States to lands beneath navigable waters within State boundaries and to the natural resources within such lands and water, to provide for the use and control of said lands and resources, and to confirm the jurisdiction and control of the United States over the natural resources of the seabed of the Continental Shelf seward of State boundaries.

The Act moved the boundary between Federal and State jurisdiction from the ordinary low-water mark and the seaward limits of inland waters to the seaward boundaries of the States. The seaward boundary of the States was established at a distance of 3 geographic miles from the coastline except offshore Florida and Texas, and there 3 leagues (9 geographical miles or approximately 10.3 statute miles) from the coastline. These were the boundaries of the States at the time the State entered the Union or as approved by Congress prior to the passage of the Act.

On September 26, 1953, the State of Alabama filed suit in the Supreme Court to test the constitutionality of the Submerged Lands Act, and on March 15, 1954, the Court denied the motion. An action was started December 19, 1955, by the United States against the State of Louisiana to establish its right to the minerals underlying the Gulf of Mexico beyond 3 geographical miles from the coastline of Louisiana and extending to the edge of the Outer Continental Shelf. Also, an accounting was requested for any sums of money derived by the State from that area after June 5, 1950. On October 12, 1956, the United States and the State of Louisiana entered into an interim agreement that divided the submerged lands into four zones with reference to the Chapman line as shown in figure 4. The Chapman line, named after a former Secretary of the Interior, was intended to represent the ordinary low-water mark and the seaward limits of inland waters along the coast of Louisiana. Since the Louisiana coastal charts were based mostly on 1933 surveys, the line was not definite and was understood at the time to be subject to modification. Zone 1 was the seaward area within 3 geographic miles of the Chapman line; zone 2 was the area from the seaward limit of zone 1 to 3 marine leagues from the Chapman line; zone 3 was the area from the seaward limit of zone 2 to the seaward boundary line of the State of Louisiana fixed by Act 33 of the 1954 Louisiana Legislature (called the "Coast Guard Line"),[6] and, zone 4 was the area extending seaward of zone 3.

Zones 2 and 3 were designated as the areas in dispute and all income from existing and future leases in the zones was to be impounded in an escrow fund until final disposition of the ownership question. The Department of the Interior was authorized to grant leases in zones 2 and 3.

On May 31, 1960, the Supreme Court delivered the opinion that Texas (fig. 5) and Florida are entitled to rights in the submerged lands extending for a distance in the Gulf of Mexico of 3 leagues from their coastlines, and that Louisiana, Mississippi, and Alabama are entitled to rights extending no more than 3 geographic miles from their coastlines. The Court denied a request for rehearing on October 10, 1960, and on December 12, 1960, entered its final decree for all five Gulf States.

---

[6]The Coast Guard Line was established under regulations promulgated by the Commandant of the Coast Guard, pursuant to an 1895 law, to define the limits of inland waters for navigational purposes. In 1954 a Louisiana Statute was enacted establishing the Boundary of the State at 3 leagues seward of this line.

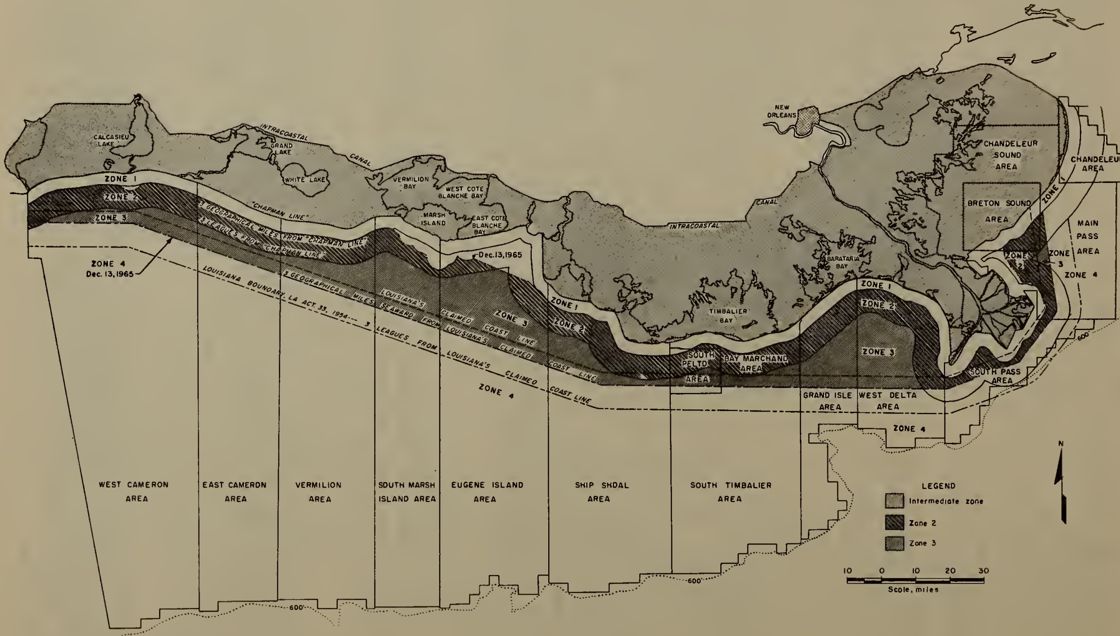


FIGURE 4. - Location of Intracoastal Canal, the Chapman Line, and Zones 1, 2, 3, and 4, Offshore Louisiana.

FIGURE 5. - Coastline, 3-League Line, and Federal Area to Outer Continental Shelf, Offshore Texas.

A supplemental decree rendered by the Court December 13, 1965, awarded certain disputed areas shown in figure 4 to Louisiana by moving parts of the Chapman line seaward. The decree also moved the seaward limit of zone 3 from 3 leagues to 3 geographical miles from Louisiana's claimed coastline. The acres in zones 1, 2, 3, and 4 as of October 12, 1956, and December 13, 1965, are as follows:

	Zone 1	Zone 2	Zone 3	Zone 4
Oct. 12, 1956..........	930,640	1,833,185	2,848,056	11,212,568
Dec. 13, 1965..........	1,083,340	1,388,153	1,465,991	12,889,664

Impounded funds in the amount of $34,547,227.42, obtained from bonuses, rentals, royalties, and severance taxes, were released to the State. Also, the decree released to the Federal Government the impounded fund (estimated to be $190,000,000) for leases in the area beyond 3 geographical miles seaward of the State of Louisiana coastline defined by Act 33 of 1954.

The approximate conventional edge of the OCS is shown by the 600-ft water-depth line in figures 4 and 5. Although the exact limit of the OCS is not defined by the Act, generally it is meant to be the point where the continental slope leading to the ocean bottom assumes a greater angle. This is where the water is 654 ft (200 meters) deep, but leases may be issued for any depth water where exploration and production are possible.

The OCS Lands Act became effective on August 7, 1953, when H.R. 5134 of the 83d Congress was signed into law as Public Law 212. The purpose of the Act is defined in the title as follows:

> To provide for the jurisdiction of the United States over the submerged lands of the Outer Continental Shelf and authorizes the Secretary of the Interior to lease such lands for certain purposes.

The Outer Continental Shelf comprises that part of the Continental Shelf which lies seaward of the portion of the submerged lands along the coast of the United States which Congress granted to the adjacent coastal States in 1953.

The responsibility for administering the leasing and operating regulations pertaining to OCS mineral resources was delegated to the Bureau of Land Management (BLM) and the U.S. Geological Survey (USGS). The leasing procedures and terms as outlined in Section 8 of Public Law 212 are summarized in appendix B.

Leases that had been issued seaward of the State boundaries (as defined in the OCS Lands Act) were validated in accordance with Public Law 212, and will be referred to in this report as validated State leases.

FEDERAL LEASING IN THE GULF OF MEXICO

Prices Paid for Oil and Gas Leases

To July 1967 a total of 16 oil and gas lease sales, two sulfur sales, and one salt sale had been held for acreage in the Gulf of Mexico. Only the oil and gas sales will be discussed in this report; a summary of the rentals, royalty, and bonus data for the 16 oil and gas leases is shown in table 4. The two types of oil and gas lease sales are the nominated and drainage sales. Nominated lease sales are held because of requests by industry for certain tracts for exploration and possible development. Drainage sales are held to develop certain tracts to prevent movement of hydrocarbons across boundary lines. Leases for tracts in both the nominated and the drainage sales are awarded to the highest qualified bidder complying with all regulations. A minimum bid of $15 per acre (except $10 per acre for one offshore Florida sale and $25 per acre for the May 1968 offshore Texas sale) has been established by the Secretary as a part of the lease terms in the nominated OCS lease sales. All drainage lease sales have had a minimum bid price of $25 per acre. All minimum bid prices are established only to eliminate nuisance bids, not to indicate the value of the leases. The minimum accepted bid is determined by the BLM on the basis of economic, geologic, and engineering data. On several occasions, bids above the minimum price have been rejected by the BLM because they determined the tracts to be more valuable than the price bid. Annual minimum royalty for leases obtained in nominated lease sales is $3 per acre, or one-sixth of the gross value of production, whichever is greater, and $10 per acre or one-sixth of the gross value of production for drainage lease sales. The annual rental for nondrainage leases has been $3 per acre, and $10 per acre for drainage lease sales, with the exception of the October 1966 drainage sale, which had both a minimum royalty and rental rate of $5.

The first Federal lease sale held after the passage of Public Laws 31 and 212 was a nomination oil and gas sale offshore Louisiana on October 13, 1954. Approximately 400,000 acres was leased for an average price of about $295 per acre. To January 1, 1968, there have been six nominated oil and gas lease sales offshore Louisiana. In each sale, March 1962 (includes March 13 and March 16 sales) being an exception, the average per-acre cash bonus paid increased. The average bonus dropped to $237 in March 1962 when about 1.9 million acres was leased for over $445 million. In July 1955 about 250,000 acres was leased for an average of $396 per acre; in February 1960 about 460,000 acres for an average of $532 per acre; and in June 1967 about 740,000 acres for an average of $685 per acre. These average bonuses are shown in both 1958 constant dollars and current dollars in figure 6. An average bonus of $348 per acre was paid for the first acreage offshore Texas. But, after unsuccessful exploration ventures on those tracts, the average per-acre bonuses were $56 in 1955, $149 in 1960, and $19 in 1962. Owing, at least in part, to increased technology in seismic exploration, the average per-acre bonus increased to about $1,100 per acre in 1968.

TABLE 4. - Rental, royalty, and bonus paid, to July 1967, for Federal Outer Continental Shelf Leases, Gulf of Mexico

Lease Date	Area leased, thousand acres	Bonus value, million dollars	Number of leases	Rental, dollars per acre	Royalty, dollars per acre 1/	Minimum bid, dollars per acre	Highest bid accepted, dollars per acre	Lowest bid accepted, dollars per acre	Average bonus, dollars per acre 2/
LOUISIANA									
10/13/54....	394.7	$116.4	90	$3.00	$3.00	$15.00	$1,220.00	$17.10	$294.84
7/12/55.....	252.8	100.1	94	3.00	3.00	15.00	2,076.80	15.52	395.92
8/11/59 3/...	38.8	88.0	19	10.00	10.00	25.00	10,442.08	76.03	2,267.78
2/24/60.....	464.0	246.9	99	3.00	3.00	15.00	2,501.51	24.22	532.07
3/13/62.....	951.8	177.3	206	3.00	3.00	15.00	3,201.00	15.83	186.23
3/16/62.....	927.7	267.8	195	3.00	3.00	15.00	3,081.00	15.10	288.63
10/9/62 3/...	16.2	43.9	9	10.00	10.00	25.00	8,480.00	166.00	2,712.79
4/28/64 3/...	32.7	60.3	23	10.00	10.00	25.00	4/ 10,490.40	104.21	1,846.69
3/29/66 3/...	35.1	88.8	17	10.00	10.00	25.00	6,112.20	243.10	2,534.43
10/18/66 5/..	104.7	99.2	24	5.00	5.00	25.00	3,128.00	33.76	946.98
6/13/67.....	744.5	510.1	158	3.00	3.00	15.00	6,500.00	21.00	685.17
TEXAS									
11/9/54.....	67.1	$23.4	19	$3.00	$3.00	$15.00	$2,209.00	$16.30	$347.84
7/12/55.....	149.8	8.4	27	3.00	3.00	15.00	177.00	17.50	56.34
2/26/60.....	240.5	35.7	48	3.00	3.00	15.00	1,026.25	16.10	148.59
3/16/62.....	28.8	.6	10	3.00	3.00	15.00	26.25	16.00	19.37
FLORIDA									
5/26/59.....	132.5	$1.7	23	$3.00	$3.00	$10.00	$16.17	$10.11	$12.92

1/ To July 1967, OCS royalty has been one-sixth of gross value of production, or the royalty value per acre, whichever is greater.
2/ The average bonus dollars per acre was derived from actual data, not from rounded figures.
3/ Drainage sale, zone 2.
4/ Highest bid to July 1967.
5/ Includes only zones 3 and 4.

Source: U. S. Bureau of Land Management. Statistical Summary, Outer Continental Shelf Lease Sales.

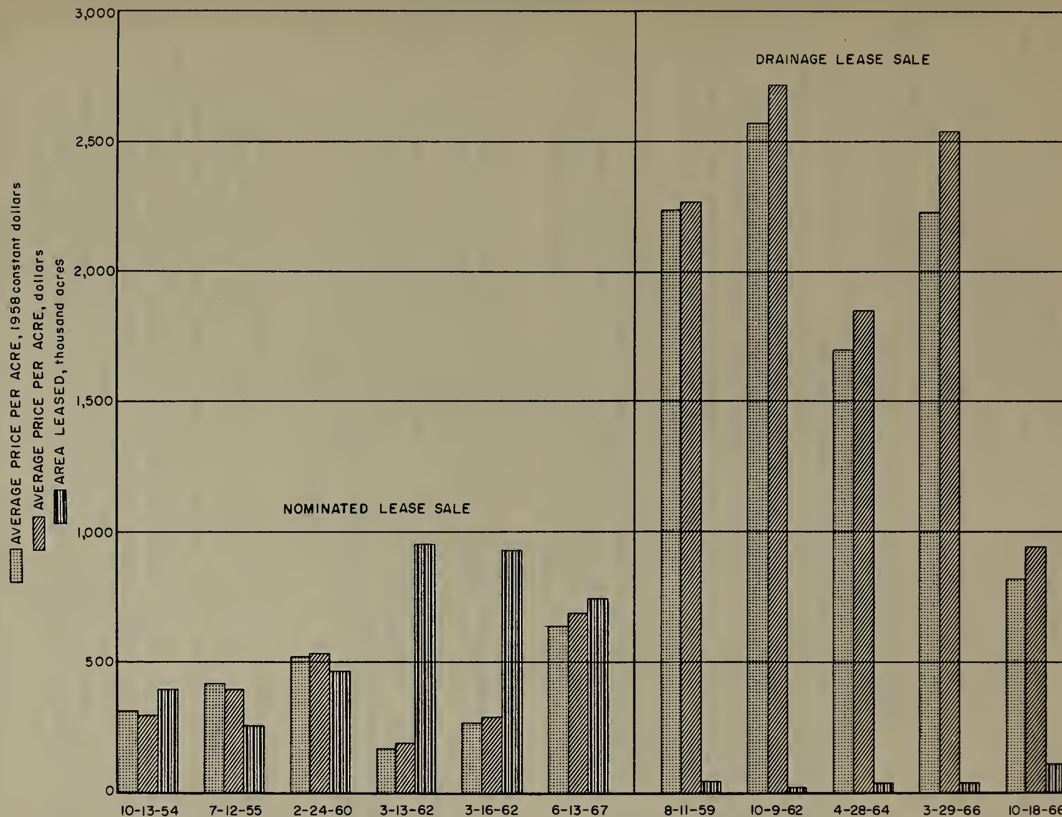


FIGURE 6. - Acreage Leased and Average Price Paid Per Acre for Federal Offshore Louisiana Sales From October 1954 Through June 1967.

To January 1, 1968, a total of 1,061 tracts covering about 4.6 million acres (including the drainage sales) had been leased by the Federal Government. The overall average bonus per acre has been $140 for Texas offshore,[7] compared with $454 for offshore Louisiana ($380 excluding drainage sales). The only lease sale offshore Florida was in 1959 and the average per-acre bonus bid was under $13. To 1968 industry had invested about $1.87 billion as initial bonus for acquisition of leases in the Federal offshore area of Texas, Louisiana, and Florida, for an average of $408 ($342 excluding drainage sales) per acre. Including the 1968 Texas sale the total initial bonus paid was $2.46 billion.

There have been five drainage lease sales in the Gulf of Mexico (all offshore Louisiana) to allow sufficient development of certain fields to prevent movement of hydrocarbons from adjacent unleased parcels to producing tracts. These have been much smaller in acreage than nominated lease sales, but have yielded a much higher average bonus per acre (fig. 6). These tracts understandably bring the highest average bonus per acre because drilling and development usually proves them to be commercially productive. To 1968 only about 10 pct of the leases on these tracts had expired or been relinquished.

The highest bonus per acre for a single tract leased since 1954 was $10,490.40 for a 1,250-acre parcel that was a southwest extension of the Timbalier Bay field. The five drainage sales represent approximately 6 pct of the total acreage leased offshore Louisiana (Federal OCS), and bonus revenue has been about 20 pct of the total from all offshore leases.

Table 5 presents a summary of Federal oil and gas lease bonuses, minimum royalties, rentals, shut-in gas payments, and royalty value of crude oil, condensate, and gas from 1953 through 1966. Minimum royalties and shut-in gas payments are made when commercial amounts of crude oil or gas have been proven, but are not being produced. Shown also is the royalty value of crude oil, condensate, and gas produced from the Federal area of the Gulf of Mexico. The combined annual royalty value of these hydrocarbons has increased from $967,892 in 1953 to $132,849,922 in 1966.

Retention of Leases

Figure 7 shows the location of all active Federal and validated State leases in zones 2, 3, and 4, offshore Louisiana. From 1953 through 1967 BLM leased approximately 4 million acres in the offshore Federal areas of Louisiana. By October 1967 leases on about 1¼ million acres had expired (table 6). Much of this 1¼ million acres has been explored, to some extent, unsuccessfully. Overall, about 640,000 acres seaward of zone 1 was under active or validated State leases offshore Louisiana in October 1967. A portion (about 300,000 acres) of huge State Lease No. 340 in the South Marsh Island area, leased in 1936, is in litigation. Considering State Lease No. 340, active or validated State leases, and active Federal leases in zones 2, 3, and 4, a little over 12 million acres remains unleased.

[7]Does not include the May 1968 sale. Approximately 535,000 acres was leased for an average of about $1,100 per acre.

TABLE 5 . - Bonus, rental, and royalty payments received from all Federal offshore oil and gas leases, 1953-66, Gulf of Mexico

Year	Lease bonuses	Minimum royalties	Rentals	Shut-in gas payments	Total	Royalty value: Oil and condensate	Royalty value: Gas	Royalty value: Total
FLORIDA								
1959	$1,711,872	-	$397,440	-	$2,109,312	-	-	-
1960	-	-	397,440	-	397,440	-	-	-
1961	-	-	397,440	-	397,440	-	-	-
1962	-	-	190,080	-	190,080	-	-	-
1963-66	-	-	-	-	-	-	-	-
Total	1,711,872	-	1,382,400	-	3,094,272	-	-	-
LOUISIANA								
8/7 - 12/31/53	-	-	$1,271,790	$30,650	$1,302,440	$719,541	$248,351	$967,892
1954	$46,935,475	-	2,781,952	86,950	49,804,377	2,043,198	705,779	2,748,977
1955	169,534,264	-	3,553,322	122,000	173,209,586	4,022,385	1,116,642	5,139,027
1956	-	-	3,259,704	79,950	3,339,654	6,519,010	1,103,698	7,622,708
1957	-	$67,201	2,930,301	110,268	3,107,770	10,222,571	1,165,294	11,387,865
1958	-	184,396	2,140,584	121,218	2,446,198	15,110,378	2,313,500	17,423,878
1959	88,035,121	171,036	1,780,026	84,984	90,071,167	21,221,318	5,318,518	26,539,836
1960	246,909,784	299,695	2,430,290	49,350	249,689,119	29,171,604	7,636,074	36,807,678
1961	-	294,998	1,984,441	37,100	2,316,539	37,250,253	9,483,489	46,733,742
1962	488,923,391	497,202	2,068,596	62,200	491,551,389	51,504,973	13,748,400	65,253,373
1963	-	632,376	12,697,917	52,950	13,383,243	59,210,457	16,136,781	75,347,238
1964	60,340,626	784,993	6,735,693	45,800	67,907,112	68,645,345	17,887,512	86,532,857
1965	-	983,059	5,604,824	38,450	6,626,333	80,406,508	19,248,110	99,654,618
1966	188,010,893	1,327,830	4,736,294	41,700	194,116,717	103,263,580	27,989,727	131,253,307
Total	1,288,689,554	5,242,786	53,975,734	963,570	1,348,871,644	489,311,121	124,101,875	613,412,996
TEXAS								
8/7 - 12/31/53	-	-	$87,840	-	$87,840	-	-	-
1954	-	-	87,840	-	87,840	-	-	-
1955	$31,794,491	-	738,570	-	32,533,061	$979	-	$979
1956	-	-	696,489	-	696,489	6,675	-	6,675
1957	-	$1,380	289,821	-	291,201	3,296	$84	3,380
1958	-	-	236,010	-	236,010	-	-	-
1959	-	-	64,269	-	64,269	141	-	141
1960	35,732,031	17,280	762,750	-	36,512,061	47	-	47
1961	-	19,123	679,320	-	698,443	-	-	-
1962	557,720	20,520	502,200	-	1,080,440	1,837	-	1,837
1963	-	35,963	424,440	-	460,403	26,627	-	26,627
1964	-	35,350	368,820	-	404,170	2,449	-	2,449
1965	-	89,640	337,454	-	427,094	1,666	-	1,666
1966	-	-	2,933	-	2,933	444,017	1,152,598	1,596,615
Total	68,084,242	219,256	5,278,756	-	73,582,254	487,734	1,152,682	1,640,416
Grand total	1,358,485,668	5,462,042	60,636,890	963,570	1,425,548,170	489,798,855	125,254,557	615,053,412

Source: U. S. Geological Survey, Conservation Division. Mineral Production, Royalty, Income, and Related Statistics, 1965-66.

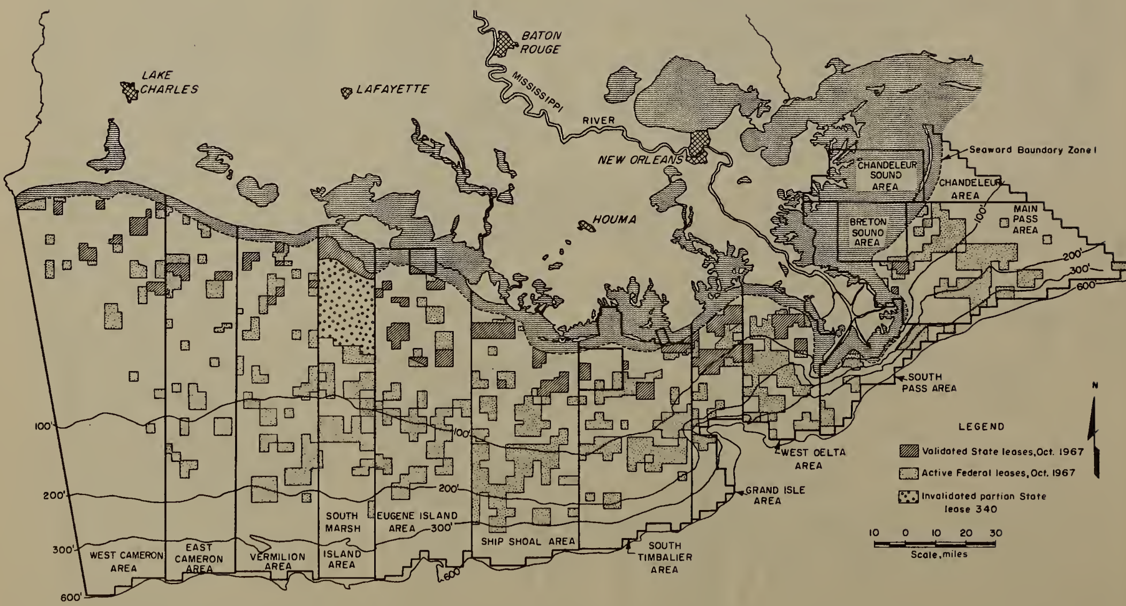


FIGURE 7. - Active Federal and Validated State Leases Seaward of Zone 1 and Invalidated Portion of State Lease 340, Offshore Louisiana, October 1967.

TABLE 6. - Federal Outer Continental Shelf oil and gas leases, Gulf of Mexico, October 1967

Lease date	Totals			Producing 1/			Productive-shut-in 1/			Expired			Held by royalty or rental payments		
	Area leased, thousand acres	Bonus value, million dollars	Number of leases	Area leased, thousand acres	Bonus value, million dollars	Number of leases	Area leased, thousand acres	Bonus value, million dollars	Number of leases	Area leased, thousand acres	Bonus value, million dollars	Number of leases	Area leased, thousand acres	Bonus value, million dollars	Number of leases
LOUISIANA															
10/13/54.......	394.7	$116.4	90	172.2	$59.9	40	25.0	$9.8	5	197.5	$46.7	45	-	-	-
7/12/55........	252.8	100.1	94	40.6	21.2	15	57.2	45.4	19	155.0	33.5	60	-	-	-
8/11/59 2/......	38.8	88.0	19	26.7	78.8	12	-	-	-	12.1	9.2	7	-	-	-
2/24/60........	464.0	246.9	99	96.4	93.9	21	205.0	75.3	43	162.6	77.7	35	-	-	-
3/13/62........	951.8	177.3	206	105.6	56.4	22	415.2	60.4	89	411.0	57.9	91	20.0	$2.6	4
3/16/62........	927.7	267.8	195	154.4	63.5	32	377.8	120.0	80	285.5	68.0	60	110.0	16.3	23
10/9/62 2/......	16.2	43.9	9	6.3	32.7	3	2.0	2.2	1	-	-	-	7.9	9.0	5
4/28/64 2/......	32.7	60.3	23	18.6	45.5	10	2.2	9.3	2	.8	.4	2	11.1	5.1	9
3/29/66 2/......	35.1	88.8	17	12.5	37.5	5	6.1	14.1	4	-	-	-	16.5	37.2	8
10/18/66 2/.....	104.7	99.2	24	-	-	-	7.2	4.1	2	-	-	-	97.5	95.1	22
6/13/67........	744.5	510.1	158	-	-	-	10.0	17.5	2	-	-	-	734.5	492.6	156
Total.....	3,963.0	1,798.8	934	633.3	489.4	160	1,107.7	358.1	247	1,224.5	293.4	300	997.5	657.9	227
DRAINAGE SALES															
Total..........	227.5	380.2	92	64.1	194.5	30	17.5	29.7	9	12.9	9.6	9	133.0	146.4	44
REGULAR COMPETITIVE SALES															
Total..........	3,735.5	1,418.6	842	569.2	294.9	130	1,090.2	328.4	238	1,211.6	283.8	291	864.5	511.5	183
TEXAS															
11/9/54........	67.1	23.4	19	5.8	4.6	1	8.6	8.6	6	52.7	10.2	12	-	-	-
7/12/55........	149.8	8.4	27	-	-	-	-	-	-	149.8	8.4	27	-	-	-
2/26/60........	240.5	35.7	48	69.1	19.5	12	1.5	.1	1	169.9	16.1	35	-	-	-
3/16/62........	28.8	.6	10	-	-	-	-	-	-	28.8	.6	10	-	-	-
Total.....	486.2	68.1	104	74.9	24.1	13	10.1	8.7	7	401.2	35.3	84	-	-	-
FLORIDA															
5/26/59........	132.5	1.7	23	-	-	-	-	-	-	132.5	1.7	23	-	-	-
GULF OF MEXICO															
Total..........	4,581.7	1,868.6	1,061	708.2	513.5	173	1,117.8	366.8	254	1,758.2	330.4	407	997.5	657.9	227

1/ Lease may be classified producing, or productive-shut in by effect of consignment to a producing or productive-shut-in unit, without actual completion of an oil or gas well on the tract.
2/ Drainage sales.

Source: U. S. Bureau of Land Management. Statistical Summary, Outer Continental Shelf Lease Sales.

A summary of all Federal Gulf of Mexico OCS oil and gas leases to October 1967 is shown in table 6. According to an October 1967 Department of the Interior OCS mineral lease summary, 407 of the total 1,061 Federal Gulf of Mexico leases acquired (including the June 1967 lease sale) had expired or had been relinquished; and 427 of the 654 active leases were classified as producing, productive-shut-in, or held by consignment to a producing or shut-in unit. A lease may be consigned to a producing or shut-in unit without having a completed oil or gas well on the tract. Of the 654 active leases, 227 (156 of these were obtained in June 1967) are held by royalty or rental payment for further disposition. Drilling and testing of some tracts leased in June 1967 commenced immediately and significant discoveries, classified as shut-in, were reported shortly thereafter. To October 1967 the average bonus paid for the producing, productive-shut-in, or assigned leases was $481 per acre compared with $188 on the leases that eventually expired. The bonus paid appears to reflect the general probability of successful exploration.

The area of the 427 productive leases is about 1.83 million acres, and the area of the 407 expired leases is about 1.76 million acres or 38 pct of the total acreage leased. All leases offshore Florida, 81 pct of the offshore Texas leases, and 32 pct of the offshore Louisiana leases had expired by late 1967.

Classification of Zones 2, 3, and 4 Leases by Water Depth

The total area of zones 2, 3, and 4 offshore Louisiana is approximately 15.7 million acres since changes made by the December 1965 supplemental decree (15.9 before decree). About 53 pct of the 15.7 million acres is in water 100 ft or deeper, and 20 pct of this area in water 300 to 600 ft deep. In each nominated sale, industry has acquired leases in progressively deeper water. To October 1967, however, only 63,000 acres of the 1.7 million acres platted for the area where water is over 300 ft deep are under lease. Of the 6.5 million acres lying in 100 to 300 ft of water, 22 pct was under active Federal lease. Validated State leases were held on nearly 40,000 acres in the 100 to 300-ft water-depth range. About 1.25 million, or 16 pct of the 7.5 million acres seaward of zone 1, lying in 100 ft or less of water was under active Federal lease in 1967, and about 8 pct was under validated State lease agreements at that date (including validated portion of State Lease 340).

About 92 pct of the acreage leased in the Gulf Coast OCS has been in the waters adjacent to Louisiana. Figure 8 shows the distribution of all offshore Louisiana leases through 1967 by approximate median water depth. The leases are as far as 90 miles from the coast. About one-third of the 934 tracts leased through 1967 are in water over 120 ft deep. Over 250 of these deeper leases are active, and more than 100 are unproductive or untested. The water depth of the active leases ranges up to about 465 ft. Of the 300 leases that have expired or were relinquished, about 80 pct were in water less than 120 ft deep.

Water depth of the 104 tracts leased in the four sales offshore Texas ranged from 40 to 120 ft, with the maximum distance from shore about 65 miles.

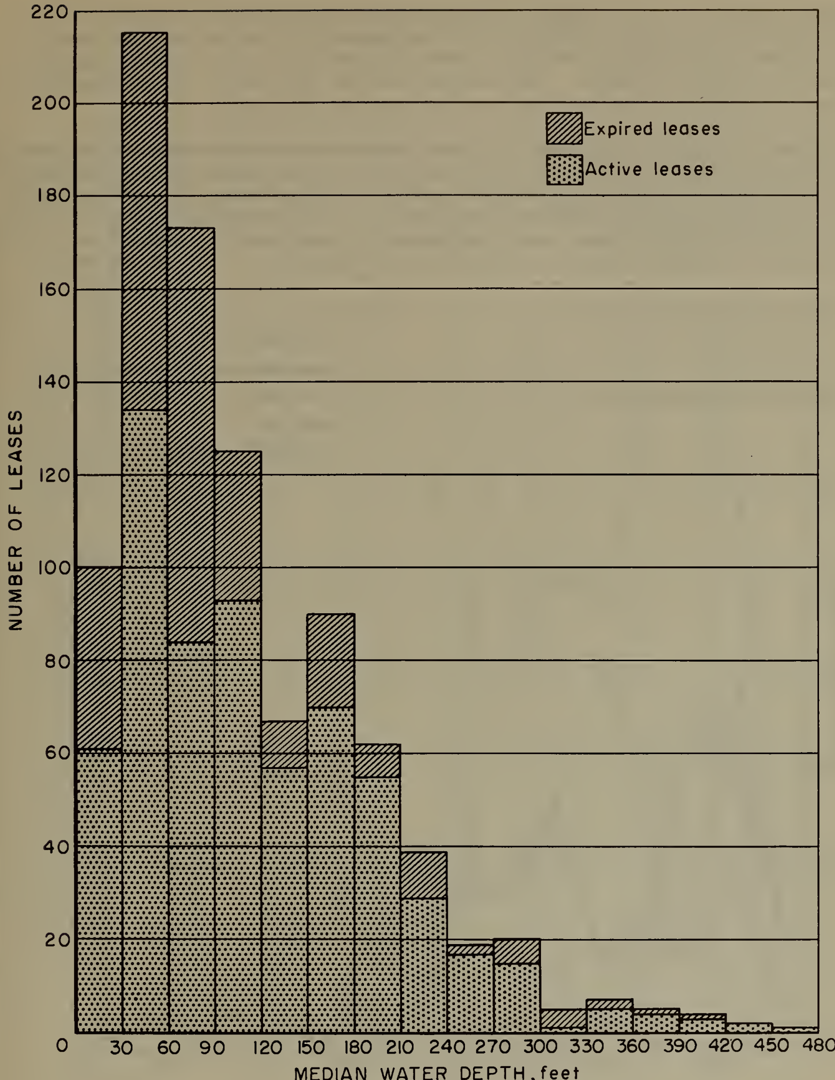


FIGURE 8. - Distribution by Median Water Depth of All Federal Leases Offshore Louisiana, October 1967.

Only 12 of the 104 tracts leased offshore Texas were in water over 100 ft in depth. The acreage leased offshore Florida ranged from 70 to 90 miles from the mainland but was within 20 miles of the island group that extends southwest into the Gulf of Mexico. Water depth of more than 50 pct of the tracts was less than 100 ft, and for the remainder was 100 to 600 ft.

Figure 9 shows a comparison of approximate median water depths of tracts in each of the nominated lease sales. The median water depth, determined from Coast and Geodetic Survey maps, is the depth of the approximate center of a tract. The average median depth of the water for all tracts generally increased in each major lease sale (the exception was the July 1955 sale). The 1954 and 1955 sales have been considered as one group in comparing water

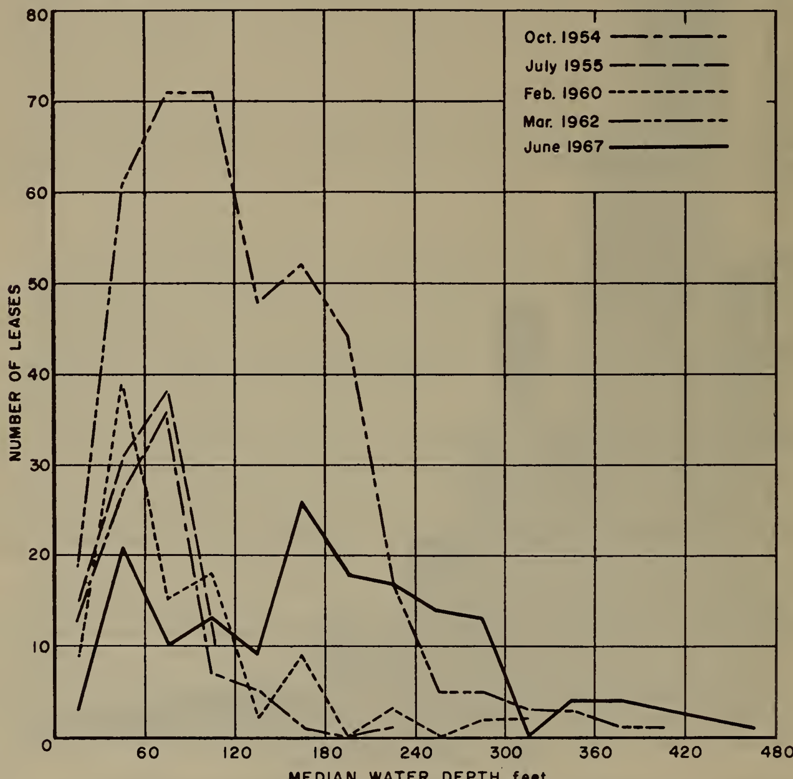


FIGURE 9. - Distribution by Median Water Depth of All Tracts Leased at Nominated Federal Lease Sales, 1954-67, Offshore Louisiana.

depth trends because the sales were only 9 months apart. The average water depth of each group was 67 ft for the first two lease sales, 89 ft for the 1960 lease sale, 125 ft for the 1962 lease sale, and 186 ft for the 1967 lease sale.

A study was made to determine if water depths of the producing tracts were increasing simultaneously with leasing depths. To do this, an analysis of each lease sale was made as shown in figure 10. Some of the tracts in figure 10 are shown in productive areas shallower than the depth of leases obtained because their median depth is more than that of the field in which they are included. The range of the median water depths of the producing

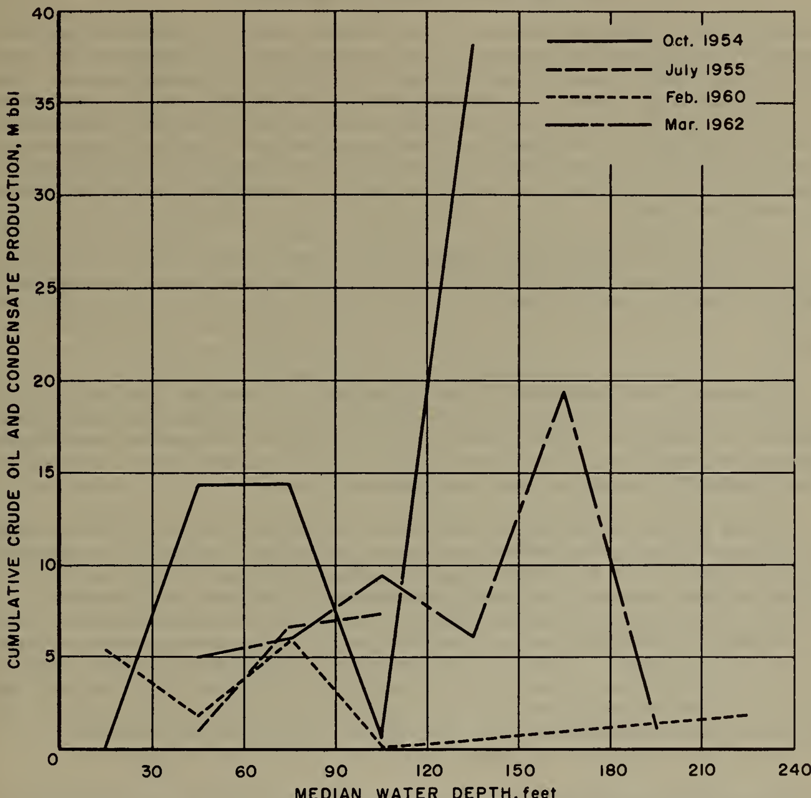


FIGURE 10. - Distribution by Median Water Depth of Cumulative Crude Oil and Condensate Production From Fields Discovered on Federal Tracts Leased From October 1954 Through March 1962, Offshore Louisiana.

fields on January 1, 1968, discovered on 1954 leases, is 20 to 138 ft; the range of the 1955 fields is 56 to 96 ft; the range of the 1960 fields is 23 to 228 ft; and the range of the 1962 fields is 57 to 208 ft. Although the trend to productive tracts in deeper water has not been as consistent as the trend in leasing, the distribution of 1962 sales compared with the 1954 sale shows a definite movement toward deeper water. These data indicate that the water depths of the tracts leased as well as the water depths of the producing fields have increased simultaneously.

GULF OF MEXICO HYDROCARBON PRODUCTION, RESERVES, AND CAPACITY

Reserves and Productive Capacity

According to the American Petroleum Institute (API), offshore crude oil reserves in the Gulf of Mexico were 2,374,576,000 bbl as of December 31, 1967. This number excludes reserves anticipated from reservoirs behind casing. Even with this exclusion, there is approximately 500,000 bbl of reserves per offshore completion compared with an average of about 55,000 bbl per completion for the United States. In summation, at the end of 1967 the Gulf of Mexico had approximately 8 pct of the total U.S. crude oil reserves, 1 pct of the producing oil well completions, and 9 pct of the production (using preliminary 1967 production data).

The importance of the Gulf of Mexico as a future source of liquid hydrocarbons is shown in a 1967 offshore study (14). The cumulative increase in liquid hydrocarbon reserves for the total United States from 1955 through 1966 was about 5 billion bbl. Of this amount, almost 50 pct was from offshore Louisiana.

In January 1968 there were 41 giant fields[8] in Louisiana including all offshore areas (7). Of these 14 are offshore, and six of the 10 largest are offshore. On January 1, 1967, there were 147 oilfields or gasfields offshore Louisiana and 20 offshore Texas. All of these fields, including location and salient production data, are listed in appendix C.

The API estimated the 90-day crude oil productive capacity offshore Texas and Louisiana to be 1,132,200 bbl per day as of January 1, 1968. The 90-day capacity is defined as the maximum daily crude oil production rate at the point of custody transfer that could be achieved in 90 days with existing wells, well equipment, and surface facilities, plus work and changes that can be reasonably accomplished within the time period using present service capabilities and personnel. Production restrictions preclude rates which would result in a significant reduction in ultimately recoverable oil, prohibit the pollution of potable water sources, and prohibit air pollution with gas or the creation of fire hazards from gas. The January 1968 combined Texas and Louisiana offshore capacity is about 9 pct of the total U.S. capacity.

---

[8]A giant field is defined as having an ultimate recovery of at least 100 million bbl.

Gas, Crude Oil, and Condensate Production

Annual Gulf of Mexico crude oil and condensate production has increased steadily from less than 1.0 pct of the U.S. total in 1954 to over 8 pct in 1966, with over 99 pct of this production from offshore Louisiana and the remainder from offshore Texas. Gulf of Mexico crude oil and condensate production from 1954 through 1966 is shown by zone in table 7; and gas production from 1954 through 1966 is shown by zone in table 8. Hydrocarbon production statistics for offshore California and Alaska (Cook Inlet) are shown in appendix A. There had been significant exploration on submerged tracts in lakes, bays, and offshore United States and other parts of the world before Federal leasing in offshore areas of the gulf coast began in 1954. As a result of activity in the Gulf of Mexico, production of crude oil and condensate from State leases offshore Texas and Louisiana was about 16 million bbl[9] during 1954 (table 7). Development of these leases and subsequent Federal and State leases offshore Louisiana and Texas increased annual production about 15 times to 244 million bbl by 1966. Using 1954 as the base year, the growth rate of Gulf of Mexico crude oil and condensate production through 1966 was about 26 pct per year. The average growth rate of domestic crude oil and condensate production through 1966, using 1954 as the base year, was 1.5 pct per year excluding Gulf of Mexico production, and 2.1 pct including it. Casinghead and natural gas production also increased significantly. The 1954 production of about 80 billion scf increased about 17 times to 1,355 billion scf in 1966. In 1967 all oil well completions in the United States, including offshore, had an average production rate of about 15 bpd, and offshore completions averaged about 150 bpd.

After ownership of offshore areas was defined in 1953, the Federal Government validated all State-leased tracts in Federal areas (zones 2, 3, and 4, fig. 4), with the exception of the major portion of State Lease 340 in the South Marsh Island area. In October 1967 there were 98 active, validated State-leased tracts offshore Louisiana, some many miles offshore. An example is the Eugene Island Block 110 field, discovered on a State-leased tract about 20 miles seaward of the Chapman line. To analyze the effect of Federal offshore lease sales in terms of oil and condensate production from fields discovered on offshore tracts, Louisiana data were divided into three groups: (1) Production from all fields in zone 1 and inside the Chapman line; (2) production from fields discovered on State-leased tracts in zones 2, 3, and 4; and (3) production from fields discovered on tracts in zones 3 and 4 leased by the Federal Government (fig. 11). The sum of these groups is the total production offshore Louisiana. In 1966 there were 60 fields in group 1, 42 fields in group 2, and 45 fields in group 3.

---

[9]Some of the production offshore Louisiana was from tracts under ownership dispute.

TABLE 7. - Annual Gulf of Mexico crude oil and lease condensate production from January 1, 1954, to January 1, 1967, bbl

	1966	1965	1964	1963	1962	1961	1960	1959	1958	1957	1956	1955	1954
LOUISIANA OFFSHORE CRUDE OIL PRODUCTION 1/													
Inside Chapman line 2/	11,132,534	10,842,866	10,465,506	9,884,908	9,024,994	8,580,238	8,390,925	7,043,274	5,244,486	5,705,486	5,345,566	18,928,000	12,802,000
Zone 1 2/	39,504,925	36,469,567	39,740,228	35,771,614	33,864,524	31,029,375	31,498,920	30,357,637	27,673,732	31,542,649	25,676,213		
Zone 2 3/	95,308,900	84,097,491	74,726,608	64,633,811	53,598,165	39,123,538	28,306,638	18,482,755	11,834,963	7,881,084	5,150,978	5,784,000	2,574,000
Zone 3 3/	39,765,675	39,805,366	27,258,250	21,327,573	16,179,899	12,930,168	10,747,989	10,154,709	8,252,333	5,668,941	3,521,262		
Zone 4 4/	37,424,736	13,796,080	11,150,490	8,305,410	6,790,407	5,984,666	4,997,335	3,655,240	2,153,698	949,063	377,745		
Total	223,136,770	185,011,370	163,341,082	139,923,316	119,457,989	97,647,985	83,941,807	69,693,615	55,159,212	51,747,223	40,071,764	24,712,000	15,376,000
LOUISIANA OFFSHORE CONDENSATE PRODUCTION 1/													
Inside Chapman line 2/	213,057	284,528	344,307	407,051	476,595	726,267	625,493	663,129	756,840	385,917	12,081	9,000	3,000
Zone 1 2/	5,982,875	4,197,437	1,737,945	633,850	768,038	727,042	750,291	446,473	321,916	57,255	7,133		
Zone 2 3/	8,920,782	6,181,166	4,516,573	4,496,162	3,806,486	2,817,295	1,695,128	1,272,890	623,384	239,109	210,271	1,010,000	547,000
Zone 3 3/	2,557,327	2,290,262	2,336,316	2,492,866	1,530,474	734,063	572,130	496,514	448,892	404,627	604,709		
Zone 4 4/	2,407,916	1,327,896	1,433,225	1,133,305	761,738	544,693	537,292	220,158	70,831	33	0		
Total	20,081,957	14,281,289	10,368,366	9,163,234	7,343,331	5,549,360	4,180,334	3,099,164	2,221,863	1,086,941	834,194	1,019,000	550,000
TEXAS OFFSHORE CRUDE OIL PRODUCTION													
State	111,782	170,846	227,786	315,702	434,417	354,044	312,354	312,748	322,833	236,100	124,745	153,586	10,393
Federal	365,788	6,309	4,195	53,135	5,304	0	0	0	0	0	0	0	0
Total	477,570	177,155	231,981	368,837	439,721	354,044	312,354	312,748	322,833	236,100	124,745	153,586	10,393
TEXAS OFFSHORE CONDENSATE PRODUCTION													
State	251,025	382,519	345,359	300,923	364,872	238,302	254,234	185,751	146,887	14,449	1,475	0	0
Federal	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	251,025	382,519	345,359	300,923	364,872	238,302	254,234	185,751	146,887	14,449	1,475	0	0
GULF OF MEXICO CRUDE OIL AND CONDENSATE PRODUCTION													
Oil	223,614,340	185,188,525	163,573,063	140,292,153	119,897,710	98,002,029	84,254,161	70,006,363	55,482,045	51,983,323	40,196,509	24,865,586	15,386,393
Condensate	20,332,982	14,663,808	10,713,725	9,464,157	7,708,203	5,787,662	4,434,568	3,284,915	2,368,750	1,101,390	835,669	1,019,000	550,000
Total	243,947,322	199,852,333	174,286,788	149,756,310	127,605,913	103,789,691	88,688,729	73,291,278	57,850,795	53,084,713	41,032,178	25,884,586	15,936,393
UNITED STATES CRUDE OIL AND CONDENSATE PRODUCTION													
Total, thousands	3,027,763	2,848,514	2,786,822	2,752,723	2,676,189	2,621,758	2,574,933	2,574,590	2,448,987	2,616,901	2,617,283	2,484,428	2,357,082
RATIO OF GULF OF MEXICO PRODUCTION TO UNITED STATES PRODUCTION													
Percent	8.06	7.02	6.25	5.44	4.77	3.96	3.44	2.85	2.36	2.03	1.57	1.04	0.68

1/ Data for 1954 and 1955 are rounded.
2/ Undisputed State area.
3/ Disputed area.
4/ Undisputed Federal area.

Sources: Louisiana Department of Conservation, Annual Oil and Gas Reports, 1954-66.
Texas Railroad Commission, Annual Reports of the Oil and Gas Division, 1954-66.

TABLE 8. - Gulf of Mexico gas production from January 1, 1954, to January 1, 1967, Mscf

Location	1966	1965	1964	1963	1962	1961	1960	1959	1958	1957	1956	1955	1954
LOUISIANA OFFSHORE CASINGHEAD GAS PRODUCTION													
Inside Chapman line.........	8,933,728	9,768,538	12,904,021	13,528,892	11,256,623	10,158,836	8,756,235	5,763,284	4,402,488	3,935,455	3,451,106		
Zone 1.........	41,028,927	35,565,868	38,932,629	35,699,528	34,949,087	31,850,849	32,303,493	30,794,247	25,935,726	31,650,419	23,896,985		
Zone 2.........	104,691,680	94,613,780	88,326,198	74,294,639	59,902,255	40,451,812	28,364,155	16,721,609	8,808,923	6,672,183	4,633,740	1/25,000,000	1/14,000,000
Zone 3.........	52,294,773	48,650,958	35,256,301	31,016,477	22,918,036	17,301,042	15,302,749	11,852,520	9,592,759	5,490,015	2,962,710		
Zone 4.........	44,930,578	15,448,216	10,224,764	6,264,678	5,016,425	4,811,869	3,955,390	2,811,337	1,423,197	585,554	188,841		
Total.....	251,879,686	204,047,360	185,643,913	160,804,214	134,042,426	104,574,408	88,682,022	67,942,997	50,163,093	48,333,626	35,133,382	1/25,000,000	1/14,000,000
LOUISIANA OFFSHORE NATURAL GAS PRODUCTION													
Inside Chapman line.........	22,843,827	22,273,368	24,479,132	24,354,101	23,566,832	20,300,554	24,083,757	24,449,964	24,813,598	15,453,421	8,428,028		
Zone 1.........	227,704,210	157,927,083	85,426,936	76,033,583	67,774,152	57,525,429	50,506,220	37,840,347	33,340,593	12,587,806	6,240,100		
Zone 2.........	429,098,002	303,113,750	232,284,572	198,414,452	172,145,655	135,401,283	101,451,407	84,598,023	63,029,003	42,680,349	38,143,561	1/96,500,000	1/66,000,000
Zone 3.........	208,811,392	205,070,069	203,610,639	180,181,967	137,608,002	96,318,857	101,042,699	91,670,257	53,654,534	41,386,119	48,581,829		
Zone 4.........	153,505,404	84,592,808	82,690,389	66,757,091	53,223,694	44,360,232	42,621,393	22,778,920	8,965,911	30,822	-		
Total.....	1,041,962,835	772,977,078	628,491,668	545,741,194	454,318,335	353,906,355	319,705,476	261,337,511	183,803,639	112,138,517	101,393,518	1/96,500,000	1/66,000,000
TEXAS OFFSHORE GAS PRODUCTION													
State..........	23,439,749	23,962,212	20,456,880	20,331,664	18,376,443	16,915,599	17,629,638	13,719,006	15,571,187	2,250,212	613,501	(2/)	(2/)
Federal........	37,801,189	23,325	38,403	-	-	-	-	-	-	-	-	(2/)	(2/)
Total.....	61,240,938	23,985,537	20,495,283	20,331,664	18,376,443	16,915,599	17,629,638	13,719,006	15,571,187	2,250,212	613,501	(2/)	(2/)
GULF OF MEXICO GAS PRODUCTION													
Total..........	1,355,083,459	1,001,009,975	834,630,864	726,877,072	606,737,204	475,396,362	426,017,136	342,999,514	249,537,919	162,722,355	137,140,401	121,500,000	80,000,000

1/ All 1954 and 1955 Louisiana gas production is from leases sold by the State, except for about 15,000 Mcf of casinghead gas produced in 1955 from Federal field, Ship Shoal Block 154. All figures are rounded.
2/ Data unavailable; quantities believed to be negligible.

Sources: Louisiana Department of Conservation, Annual Oil and Gas Reports, 1954-66.
Texas Railroad Commission, Annual Reports of the Oil and Gas Division, 1954-66.

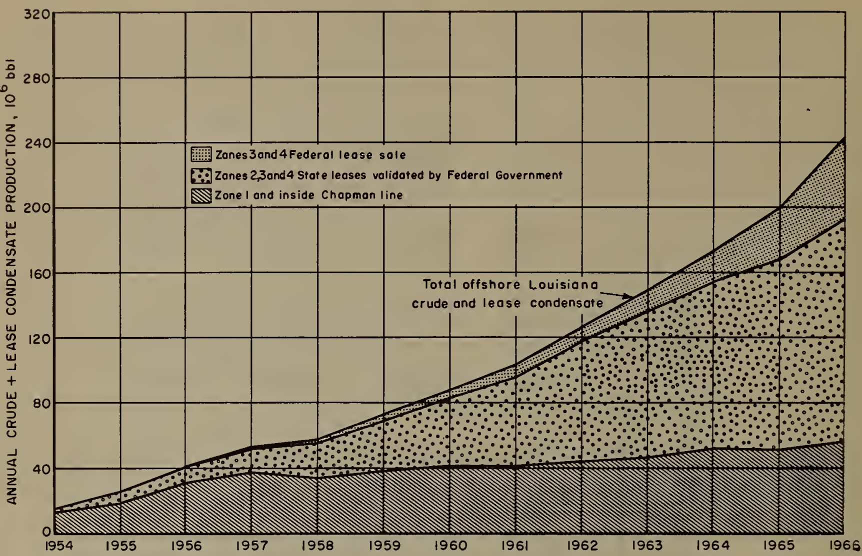


FIGURE 11. - Annual Crude Oil and Lease Condensate Production From Fields by Discovery Lease Vendor, Offshore Louisiana, January 1954 to January 1967.

Offshore Texas only one tract seaward of the 3-league line has been leased by the State and this lease has been validated by the Federal Government (fig. 12). The Texas offshore crude oil and condensate production data (table 7) are divided into two groups: (1) Production from fields discovered on State-leased tracts, which are within 3 leagues of the Texas coastline, and, (2) production from fields discovered on Federal tracts, which are seaward of a line 3 leagues from the Texas coastline. Fields discovered on Federal tracts produced less than 100,000 bbl per year until 1966 when about 366,000 bbl was produced (nearly all from the Federal Block 288 field).

To 1967 both the annual and cumulative production from fields discovered on Federal tracts was less than that from State-owned tracts or validated State-leased tracts in Federal areas. An analysis of offshore Louisiana (fig. 11) shows that production from fields discovered on Federal tracts in zones 3 and 4 has increased from 0 pct of total offshore Louisiana production in 1954 to over 20 pct in 1966. The increase from fields discovered on validated State-leased tracts in zones 2, 3, and 4 was from around 20.1 to 56.0 pct, and the decrease from tracts in zone 1 and inside the Chapman line was from over 80 to about 23 pct of total offshore Louisiana production during this time. Over half of the increase from Federal tracts in zones 3 and 4 has occurred since 1963.

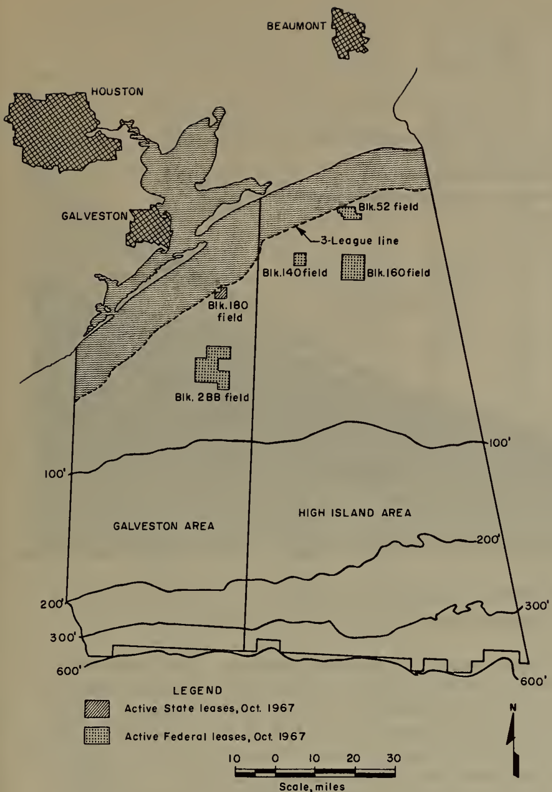


FIGURE 12. - Location of Active Federal and Validated State Leases Seaward of the 3-League Line, Offshore Texas, October 1967.

To determine the effect of Federal nominated and drainage lease sales in terms of crude oil and condensate production from tracts purchased at each sale, offshore Louisiana data were divided into four groups: (1) From all tracts in zone 1 and inside the Chapman line; (2) from tracts in zones 2, 3, and 4 leased by the State and validated by the Federal Government; (3) from tracts in zones 3 and 4 leased by the Federal Government at nominated lease sales; and, (4) from tracts in zones 2, 3, and 4 leased by the Federal Government at drainage lease sales (fig. 13). Note that in this grouping the production is from tracts, while the preceding grouping (fig. 12) gave production from fields. Production from all tracts leased by the Federal Government has increased from 0 pct of total offshore Louisiana production in 1954 to over 32.0 pct in 1966. Production from Federal areas was comprised of about 24 pct from competitive lease sales and about 8 pct from drainage lease sales. Production from zones 2, 3, and 4 State-leased tracts validated by the Federal Government increased from about 20 pct of total offshore Louisiana production in 1954 to about 45 pct in 1966. During this same period, production from tracts inside the Chapman line and in zone 1 continued to increase but represented only about 23 pct of the total in 1966.

The lease date, discovery date, and annual crude oil and condensate production from fields discovered on tracts offered during Federal nominated lease sales in 1954, 1955, 1960, and 1962 are presented in table 9 and in figure 14. The time lag between lease date and discovery date is generally less than 3 years but the time lag between lease date and production date has been up to 12 years as with the Eugene Island Block 77 field. Gasfields and

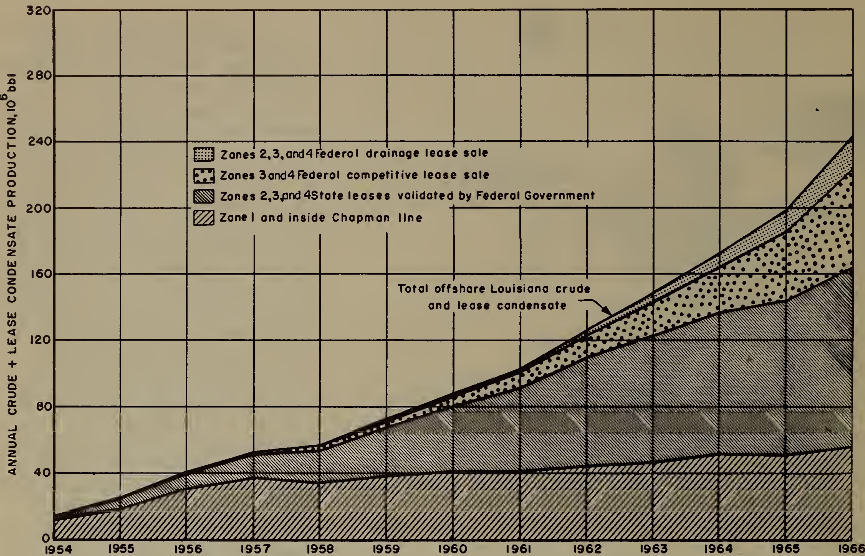


FIGURE 13. - Annual Crude Oil and Lease Condensate Production From Federal and State Leases, Offshore Louisiana, January 1954 to January 1967.

gas-cap fields generally have a much greater time lag between the lease and production dates than do oilfields. Another factor that can cause disruption of production from the offshore oil and gasfields is hurricane damage. In addition to wind and wave action, severe damage to wells and production equipment is often caused by debris carried by hurricanes. An indication of how the 1964 and 1965 hurricanes (Hilda and Betsy) affected production of some fields discovered on Federal leases is shown in table 9. For example, oil production decreased from 597,032 bbl in 1965 to 0 bbl in 1966 in the West Delta Block 117 field after all platforms were destroyed in September 1965.

Historical production data may be of little value in predicting the time frame of increasing production. For example, figure 14 shows that in 1961 production from the acreage leased in the 1954 sale had started to decline, and apparently had passed its peak. Five years later, however, the annual production had quadrupled. One explanation would be that an increase in demand permits development of productive-shut-in acreage and/or increased rate of production from developed acreage. Time lags from lease dates to exploration dates, coupled with the 1,107,700 acres classified productive-shut-in (October 1967), indicate a potential significant increase in future hydrocarbon production.

TABLE 9 . - Offshore Louisiana annual crude oil and condensate production from fields discovered on Federal leases, barrels

Field	Block	Discovery date	Date first production[1]	Approximate water depth, ft	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	Cumulative 1/1/67
OCTOBER 13, 1954, SALE																	
Ship Shoal...........	154	8/55	8/55	50	43,001	377,124	868,393	1,520,035	1,802,535	1,570,359	1,476,141	1,545,174	1,436,994	2/1,137,026	807,879	1,652,144	14,236,805
Eugene Island........	175	7/56	5/58	80	-	522	759	140,261	248,017	256,832	245,407	253,462	263,355	3/197,361	-	57,605	1,663,581
Do.................	188	10/56	10/56	65	-	99	23,986	109,270	739,681	1,030,685	909,804	810,854	867,997	1,230,169	1,418,339	2,203,089	9,343,973
Timbalier, South.....	135	12/56	7/57	130	-	-	54,822	111,489	107,540	71,516	418,427	1,296,245	2,976,583	4,888,286	6,753,014	9,576,994	26,254,916
Vermilion............	120	7/57	4/58	70	-	-	778	235,216	438,592	379,677	353,332	357,931	341,707	284,635	224,665	217,218	2,833,751
Timbalier, South.....	131	3/58	7/59	140	-	-	-	37,504	318,899	692,564	516,519	700,127	1,738,233	2,300,101	2,623,231	2,923,050	11,850,228
Eugene Island........	184	3/56	5/60	70	-	-	-	-	-	73,066	126,047	81,416	60,080	33,996	34,370	40,214	449,189
Vermilion............	164	1/57	4/64	90	-	-	-	-	-	-	-	-	-	52,501	58,440	51,876	162,817
Eugene Island........	53	7/57	12/64	20	-	-	-	-	-	-	-	-	-	-	12,983	17,595	30,578
Do.................	198	12/58	2/66	95	-	-	-	-	-	-	-	-	-	-	-	439,396	439,396
Do.................	77	5/56	2/66	20	-	-	-	-	-	-	-	-	-	-	-	192,693	192,693
Total...........	-	-	-	-	43,001	377,745	948,738	2,153,775	3,655,264	4,074,699	4,045,677	5,045,209	7,684,949	10,124,075	11,932,921	17,371,874	67,457,927
JULY 12, 1955, SALE																	
Timbalier, South.....	86	12/56	9/58	90	-	206	562	103,445	347,640	113,012	193,986	131,861	73,584	76,026	90,109	47,079	1,177,510
Eugene Island........	208	9/58	3/60	90	-	-	-	141	-	308,729	1,312,804	1,527,028	1,372,618	4/991,395	400,209	655,045	6,567,969
Ship Shoal...........	139	9/57	4/62	60	-	-	-	-	65	175	524	339,863	373,153	170,966	11,655	-	896,401
Do.................	176	11/56	2/60	100	-	-	-	-	-	686,715	840,778	996,718	1,078,239	5/796,140	495,534	1,256,822	6,150,946
East Cameron.........	160	9/56	Shutin	80	-	-	175	-	-	-	-	-	-	-	-	-	175
Total...........	-	-	-	-	-	206	737	103,586	347,705	1,108,631	2,348,092	2,995,470	2,897,594	2,034,527	997,507	1,958,946	14,793,001
FEBRUARY 24, 1960, SALE																	
Eugene Island........	100	8/60	11/60	25	-	-	-	-	-	8,697	1,069,218	1,007,674	805,851	655,807	928,069	894,916	5,370,232
Ship Shoal...........	169	9/60	10/61	45	-	-	-	-	-	-	21,951	141,483	141,099	96,292	87,913	82,225	570,963
South Marsh Island...	23	8/60	6/62	70	-	-	-	-	-	-	-	254,771	685,188	1,132,233	1,765,574	1,854,179	5,691,945
Vermilion............	129	5/61	7/63	65	-	-	-	-	-	-	-	-	27,257	55,468	61,025	42,054	185,804
Do.................	131	8/60	10/63	55	-	-	-	-	-	-	-	-	72,098	394,222	325,276	305,215	1,096,811
West Delta...........	105	8/64	8/65	235	-	-	-	-	-	-	-	-	-	-	75,551	1,701,043	1,776,594
West Cameron.........	180	8/61	12/65	50	-	-	-	-	-	-	-	-	-	-	50	117,027	117,077
South Marsh Island...	48	3/61	1/66	95	-	-	-	-	-	-	-	-	-	-	-	153,732	153,732
Total...........	-	-	-	-	-	-	-	-	-	8,697	1,091,169	1,403,928	1,731,493	2,334,022	3,243,458	5,150,391	14,963,158
MARCH 1962 SALE																	
South Pelto..........	23	7/62	5/63	60	-	-	-	-	-	-	-	-	209,268	436,566	467,808	535,753	1,649,395
Ship Shoal...........	208	7/62	6/63	95	-	-	-	-	-	-	-	-	561,816	2,177,126	3,160,831	3,506,092	9,405,865
West Delta...........	73	1/63	11/63	170	-	-	-	-	-	-	-	-	3,441	1,427,452	6,466,873	10,840,562	18,738,328
Do.................	117	6/63	11/63	210	-	-	-	-	-	-	-	-	54,636	74,739	6/597,032	-	726,407
South Marsh Island...	6	9/62	2/64	60	-	-	-	-	-	-	-	-	-	603,364	1,292,369	1,357,264	3,252,997
Timbalier, South.....	176	4/63	3/64	140	-	-	-	-	-	-	-	-	-	193,782	254,115	535,626	983,523
West Delta...........	41	10/64	11/64	80	-	-	-	-	-	-	-	-	-	63,729	2,199,514	3,620,966	5,884,209
Eugene Island........	238	2/64	12/64	125	-	-	-	-	-	-	-	-	-	15,760	225,467	782,049	1,023,276
South Marsh Island...	73	12/63	12/64	130	-	-	-	-	-	-	-	-	-	24,929	597,441	1,635,534	2,257,904
Vermilion............	245	6/62	11/65	125	-	-	-	-	-	-	-	-	-	-	11,465	1,707,370	1,718,835
Eugene Island........	276	9/64	6/66	160	-	-	-	-	-	-	-	-	-	(7/)	156	691,335	691,491
Ship Shoal...........	274	5/65	2/66	205	-	-	-	-	-	-	-	-	-	-	161	287,194	287,355
South Marsh Island...	27	12/65	9/66	90	-	-	-	-	-	-	-	-	-	-	-	53,897	53,897
Vermilion............	250	4/63	10/66	140	-	-	-	-	-	-	-	-	-	-	-	37,545	37,545
Grand Isle...........	82	6/65	Abandoned 5/67	200	-	-	-	-	-	-	-	-	-	-	-	3,560	3,560
East Cameron.........	89	8/65	10/66	60	-	-	-	-	-	-	-	-	-	-	-	1,225	1,225
Timbalier, South.....	172	4/65	Shutin	100	-	-	-	-	-	-	-	-	-	-	-	-	-
Do.................	228	8/65	Shutin	220	-	-	-	-	-	-	-	-	-	-	-	-	-
East Cameron.........	224	12/66	Shutin	110	-	-	-	-	-	-	-	-	-	-	-	-	-
Total...........	-	-	-	-	-	-	-	-	-	-	-	-	829,161	5,017,447	15,273,232	25,595,972	46,715,812

1/ Approximate date of sustained production.
2/ Hurricane Hilda destroyed two 6-pile platforms supporting 7 wells.
3/ Hurricane Hilda destroyed a 16-pile, 4-well platform, and 2 other platforms with 1 well each.
4/ Hurricane Hilda collapsed three 8-pile platforms supporting 16 wells.
5/ Hurricane Hilda destroyed three production platforms supporting eight wells.
6/ Hurricane Betsy destroyed 2 platforms supporting 14 wells.
7/ Hurricane Hilda destroyed an 8-pile drilling platform supporting one producing well.

Source: Louisiana Department of Conservation, Annual Oil and Gas Reports, 1955-66.

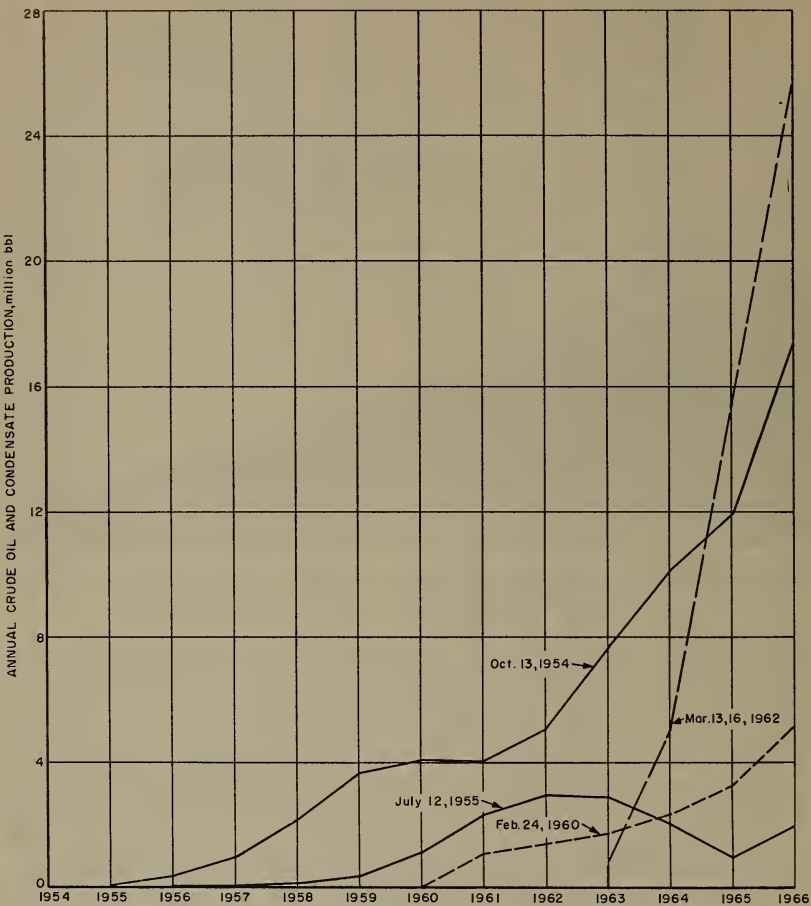


FIGURE 14. - Annual Crude Oil and Condensate Production From Fields Discovered on Federal Leases, Offshore Louisiana.

Well Count and Multiple Completion Regulation

A November 1967 well count showed that in zones 2, 3, and 4 a total of 6,292 holes had been drilled. Of these, 2,075 had been plugged and abandoned, 2,997 were producing hydrocarbons, and 1,220 were shut-in or temporarily abandoned. The producing wells were comprised of the following completions: 1,739 singles; 1,188 duals; 66 triples; and 4 quadruples.

Effective June 7, 1960, the Louisiana Department of Conservation issued statewide Order 29-C-1, which stated that until further notice no permits would be issued for the multiple completion of oil wells in oil pools not previously approved for multiple completion. The Department of Conservation rescinded the ban of multiple completions because, after hearing additional evidence on August 9, 1960, they concluded unnecessary wells would be drilled. This would place a financial hardship on a substantial segment of the oil and gas industry in Louisiana. On September 1, 1960, the multiple completion rule (29-C-1) was amended by rule 29-C-2, which permitted the dual completion of oil wells. The completion limitation to dual wells was still in effect as of January 1, 1968. Limiting multiple completions (and not changing other regulations) has the effect of reducing the amount of petroleum produced.

Proration of Production

The allowables for all offshore Louisiana wells are set by the Louisiana Department of Conservation, and offshore Texas allowables are set by the Texas Railroad Commission and the USGS. A comparison of the Louisiana and Texas depth-bracket allowables for a 100 pct market demand factor for onshore and offshore wells is shown in table 10.

Conservation of Offshore Petroleum

Offshore Louisiana there are 10 fields (85 reservoirs) with active gas-injection projects and eight fields (24 reservoirs) with active water-injection (some have both water and gas injection) projects. In 1966 the combined oil and condensate production from these fields was about 37 million bbl, or approximately 15 pct of the total offshore Louisiana production.

In addition to the active projects, 41 reservoirs have proposed projects. Engineering estimates indicate that from the active secondary recovery projects the ultimate recovery of oil will be increased about 240 million bbl. From proposed projects it has been estimated that the ultimate recovery will be increased by about 37 million bbl (5).

Methods of Transporting Offshore Production

Offshore Louisiana liquids are transported to shore both by barge and by a system of pipelines and flowlines. Pipelines are common carriers that move clean oil and gas onshore after treatment at offshore facilities, whereas flowlines move untreated fluids to onshore separation facilities. Generally, the fields in deeper water and farthest offshore are not as fully developed, so the pipeline-flowline system does not extend to these fields. Barges are often used in the interim between field discovery and completion of a pipeline or flowline. In zones 2, 3, and 4 the BLM issues pipeline permits and the USGS issues flowline permits. Operators who barge their oil to onshore facilities and apply to the USGS may receive a credit for this expenditure. Barging allowances ranging from 10.5 cents to 45 cents per bbl had been granted as of January 1, 1967. The USGS also may grant a pipeline credit based on the cost of the line and maintenance divided by the number of barrels run. Pipeline allowances have ranged from 1.4 cents to 40 cents per bbl.

TABLE 10. - Offshore Louisiana and Texas depth-bracket allowable,[1] bpd

Depth interval, ft	Onshore				Offshore			
	40 acres		80 acres		40 acres		80 acres	
	Texas[2]	Louisiana[3]	Texas[2]	Louisiana[3]	Texas[4]	Louisiana[3]	Texas[4]	Louisiana[3]
0- 2,000....	74	80	129	120	200	193	330	233
2,000- 3,000....	78	95	135	143	220	214	360	262
3,000- 4,000....	84	114	144	171	245	238	400	295
4,000- 5,000....	93	134	158	201	275	265	445	332
5,000- 6,000....	102	159	171	239	305	296	490	376
6,000- 7,000....	111	186	184	279	340	331	545	424
7,000- 8,000....	121	214	198	321	380	379	605	486
8,000- 8,500....	133	239	215	359	420	416	665	536
8,500- 9,000....	142		229					
9,000- 9,500....	157	274	250	411	465	463	730	600
9,500-10,000....	172		272					
10,000-10,500....	192	310	300	465	515	512	800	667
10,500-11,000....	212		329					
11,000-11,500....	237	347	365	521	565	559	875	733
11,500-12,000....	262		401					
12,000-12,500....	287	383	436	575	620	605	950	797
12,500-13,000....	312		471					
13,000-13,500....	337	431	506	647	675	668	1,030	884
13,500-14,000....	362		543					

1/ Below 8,000 ft, depth-bracket allowable data in columns 2, 4, 5, 6, 7, and 8 are for 1,000-ft intervals.
2/ Effective January 1965.
3/ Effective March 1953.
4/ Effective January 1966.

Sources: Louisiana Department of Conservation.
Texas Railroad Commission.

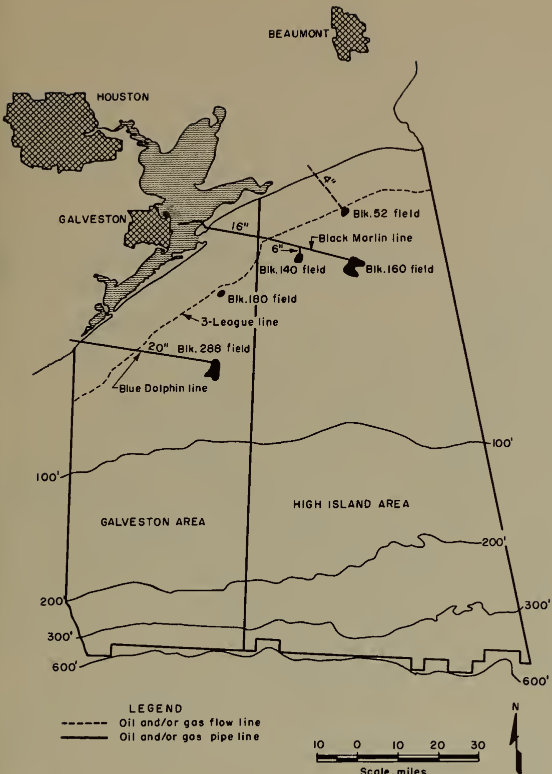


FIGURE 15. - Approximate Location of the Existing Pipeline-Flowline System, Offshore Texas, March 1968.

Most of the producing oilfields in the Federal area offshore Texas are connected with a pipeline-flowline system as presented in figure 15. The Blue Dolphin pipeline is a 20-in-diameter line about 25 miles long, from Galveston area Block 288 field to shore. The Black Marlin is a 16-in-diameter pipeline about the same length, connecting High Island Blocks 140 and 160 fields with shore facilities. In this area there is only one flowline, a 4-in-diameter line from the Federal Block 52 field to shore.

A December 1966 survey (9) indicated that about 5,000 miles of pipelines and flowlines had been constructed offshore Louisiana at that time and new work was adding about 700 miles per year. About 1,350 miles of pipeline offshore Louisiana in zones 2, 3, and 4 were either completed, under construction, or proposed as of March 1968. Figure 16 shows the approximate location of the between-field and the field-to-shore proposed, under construction, and existing pipeline-flowline system offshore Louisiana as of March 1968. Both proposed and completed lines are shown because operators have 5 years after they obtain a permit to complete a line and give notification of completion. All lines shown depict the location and direction as nearly as possible, but in some of the more congested areas, location and direction are partially schematic. Primary intent of the map is to emphasize the considerable amount of field-to-shore pipeline and flowline installations in operation or planned in zones 2, 3, and 4.

Pipelines range in diameter from 3-in to 20-in. The longest pipeline permit issued by the BLM was for an 80-mile, combination 14- and 16-in system, completed in 1966, connecting several fields in the Eugene Island and Ship Shoal areas to shore. Flowline sizes range from 4- to 30-in-diameter. The

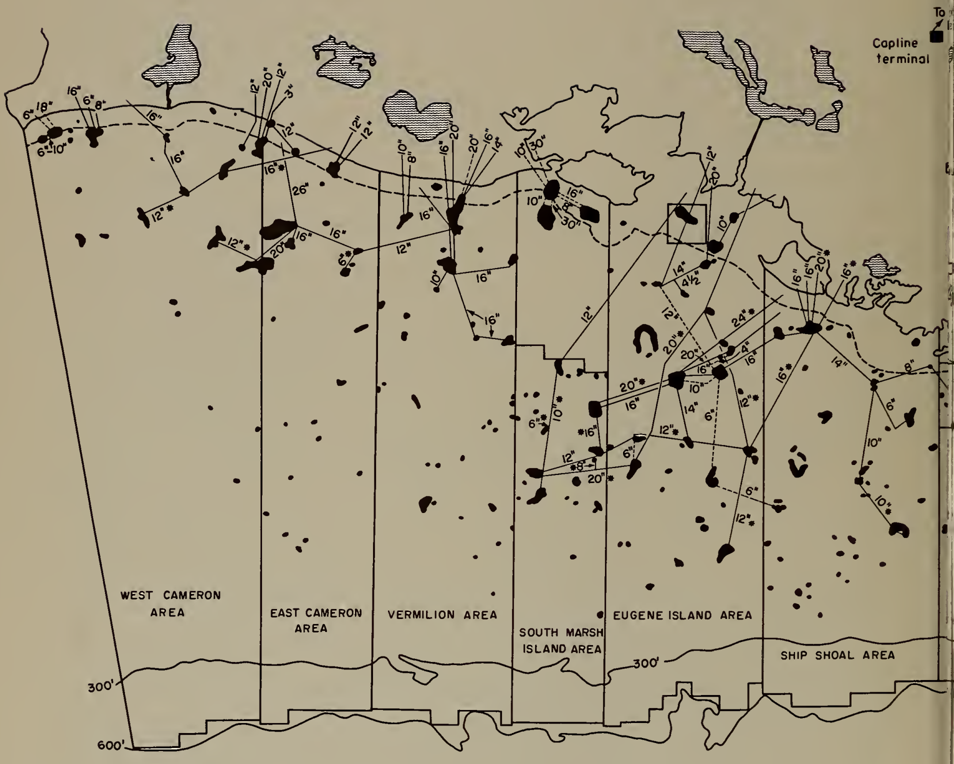
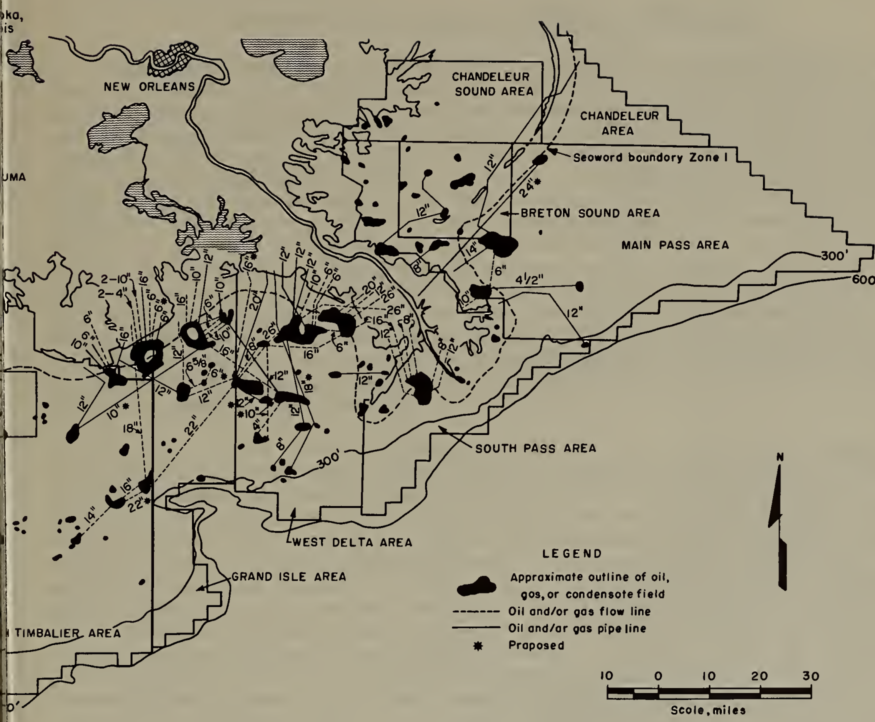


FIGURE 16. - Approximate Location of the Proposed and Existing



eline-Flowline System, Offshore Louisiana, March 1968.

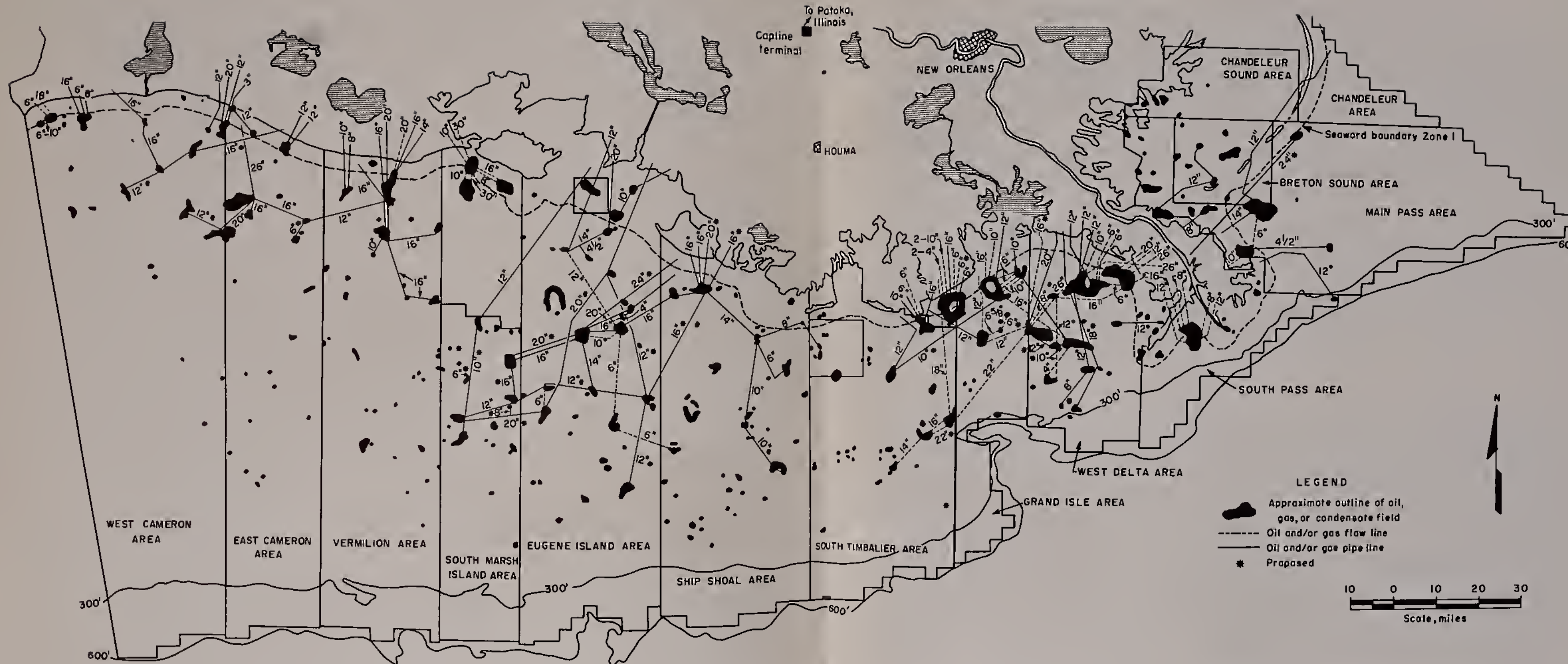


FIGURE 16. - Approximate Location of the Proposed and Existing Pipeline-Flowline System, Offshore Louisiana, March 1968.

longest system is about 45 miles of 22-in-diameter line from South Timbalier Block 135 field, through South Timbalier Block 131 to West Delta Block 41 field. Another large-diameter line carries fluids 20 miles to shore in a 26-in pipe from West Delta Block 41 field via the West Delta Block 30 field.

A March 1967 survey of the methods used to transport offshore Louisiana crude oil and condensate showed that 25 pct was barged and 75 pct was moved by the pipeline-flowline system.

TECHNOLOGY ADVANCEMENTS IN OFFSHORE OPERATIONS

Thus far, technology has progressed continuously to allow operators to move into deeper water each successive lease sale. Distance from shore, even when the water is comparatively shallow, becomes an important factor in storage and transportation of produced fluids. To explore and develop the thousands of acres leased in the Gulf of Mexico, industry developed the technology, procedures, and equipment necessary to drill in deeper water as shown by the depth rating of rigs working in the Gulf of Mexico from 1959 to July 1, 1967 (table 1). The floating units all have a depth rating of at least 600 ft of water. In the Gulf of Mexico, the 100-ft water-depth contour is up to a maximum 80 miles offshore on the gradually sloping seafloor in the western areas offshore Louisiana, while the 600-ft water mark is less than 20 miles from land near the Mississippi Delta area where the bottom slope is much more abrupt. To date the farthest proved reserve (shut-in) is 90 miles from the Louisiana coastline. The maximum water depth offshore Gulf of Mexico in which a production platform has been installed is approximately 340 ft in the South Pass area offshore Louisiana.

An early method of drilling and completing wells in the Gulf of Mexico was with the use of a small, fixed platform constructed with timber or steel piling to support the derrick and drilling rig, and a floating tender to supply all the support material, including living quarters for workers. Caissons driven into the ocean floor protect the casings of wells completed from these platforms. In the 1950's this method was generally replaced by the method of exploring prospects with mobile or floating rigs, and then designing large, expensive platforms for development drilling and production operations. These platforms consist of steel, tubular piling driven through vertical tubes strengthened by horizontal and diagonal braces. Designers make the decision on the optimum strength of a platform, based on engineering studies of forces created by hurricanes. Platforms, usually designed with eight to 12 piles, are capable of supporting 12 to 24 wells. These structures are self-contained and do not require a tender. In November 1967 there were 40 production platforms, 455 drilling platforms, and 963 caissons in the Gulf of Mexico.

The ultimate water depth in which the present tower-type construction may be used will probably be limited by economics rather than technology. Some experts think the economic limit may occur at about 600 ft water depth. Therefore, completions outside the Continental Shelf (generally where water depth is about 600 ft and begins to increase rapidly) will depend on improved technology. One possible change in the current method of development is to use underwater completion methods. With techniques such as pictured in figure 17 (11-12),

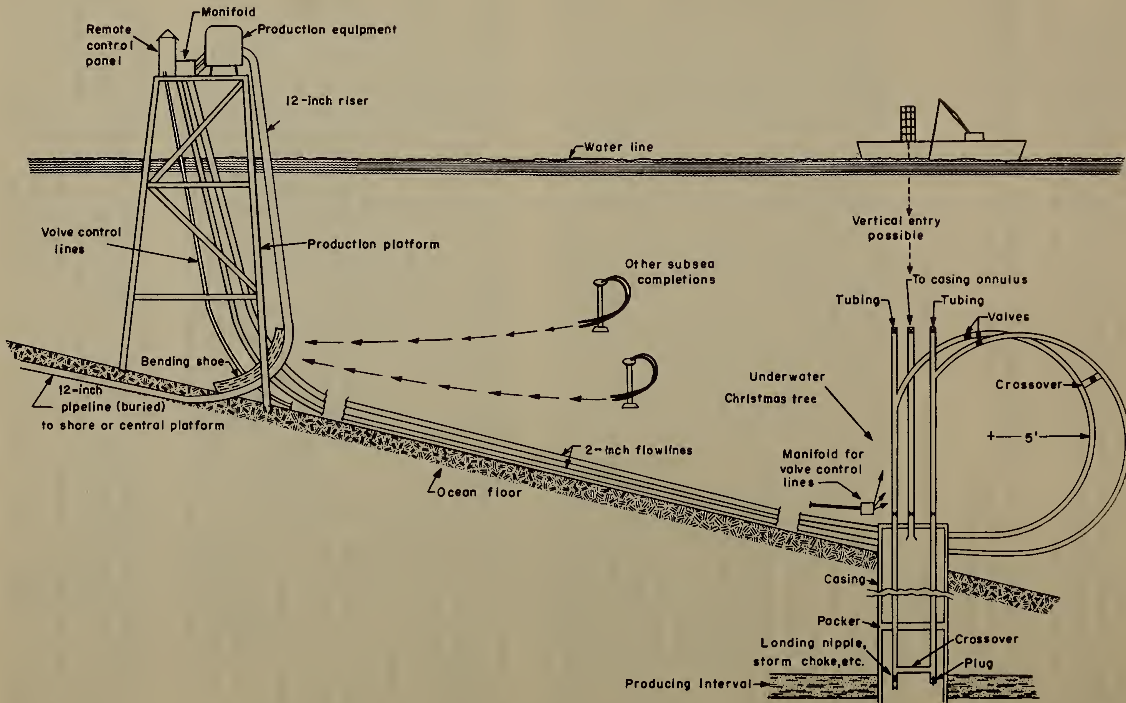


FIGURE 17. - Scheme of Subsea Well Completion Operated From a Distant Platform.

the area for possible development could be extended to deeper water. If the wellhead is on or near the floor of the sea, the fluids can be moved to a platform in more shallow water, as shown in figure 17.

The subsea wellhead completion assembly (12) is operated by a dual flowline and tubing installation technique, with hydraulic control lines and valves. This system permits fluid reversing; therefore some remedial workover and other special well bore treatment is possible. Paraffin removal, acidizing, squeeze cementing, and perforating have been successfully undertaken in a test well operating offshore in shallow water. The 2-in flowlines extended to a platform about 1 mile from the wellhead and the various operations were remotely performed, using specially designed pump-down tools. A panel on the platform contained hydraulic valve controls and remote valve position indicators; a manifold for tool placement-removal is also part of the necessary equipment. The 5-ft-radius bends in the line at the wellhead were sufficient to allow passage of the various knuckle-jointed tools and tool carriers. Vertical entry into the wellhead is possible for such other type workovers as tubing and packer removal, and Christmas tree maintenance.

COSTS OF COMPLETING OFFSHORE AND ONSHORE WELLS

Based on 1965 data (2) the average depth of an onshore well was 4,452 ft and the average cost in current dollars (not including artificial lift equipment or lease facilities) was $51,000. The average depth of an offshore well was 10,500 ft and cost, in current dollars, $412,000. Offshore well costs include platforms, barges, tenders, and other related services. These costs indicate that an average offshore well costs about 8 times as much as the average well drilled onshore in the United States.

The average cost of completing Gulf of Mexico and U.S. onshore wells from 1953 through 1965 is shown on figure 18 (2). These data were not available for the years 1954, 1957, and 1958. All costs have been converted to constant dollars using price deflators for the gross national product where 1958 = 100. From 1953 to 1956 there was a marked increase in the cost of an average offshore well. From 1959 to 1964, however, there was a decline in the costs for an average offshore well even though operators were continuing to move into deeper water. This cost reduction can be attributed, at least in part, to the increased technology gained from previous operations in this particular type of environment. In contrast, the average cost of an onshore well has remained almost constant from 1953 through 1965. The cost (using constant dollars) to drill and equip an offshore well was about 6 times the cost to drill an onshore well in 1953, 9 times the cost in 1956, and 8 times the cost in 1959 and 1965.

Water depth, distance from shore, nature of foundation sediments, and slopes of the ocean floor near the Continental Shelf margins are all important factors in installation and development costs of some tracts. One offshore operator has stated (14) that from onshore to offshore in 100 ft of water the capital requirement about doubles, and is estimated to increase another 70 pct in 400 ft of water.

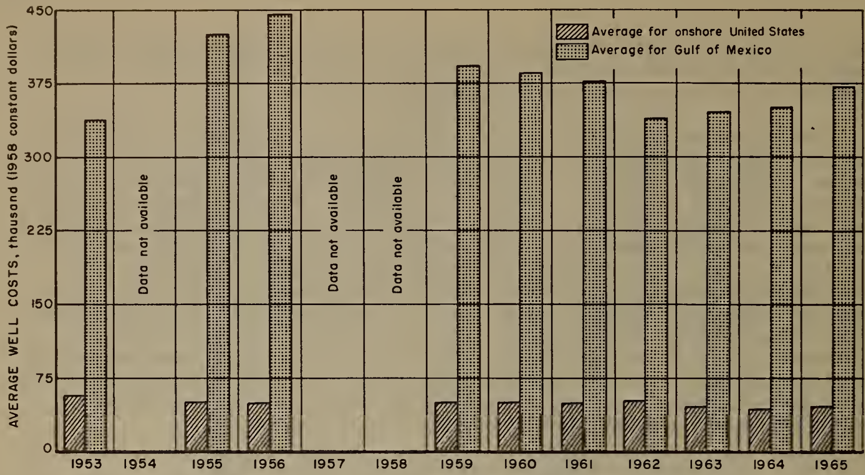


FIGURE 18. - Average Cost of Completing Offshore Wells and Onshore Wells in the United States, 1953-65.

SUMMARY AND PRODUCTION OUTLOOK

The Federal Government had leased, as of January 1, 1968, about 4.6 million acres in the Gulf of Mexico for about $1.87 billion. As of late 1967, about 50 pct of the Federal leases acquired prior to June 1967 (there had been little time to initiate drilling programs on leases acquired in June 1967) were classified producing, productive-shut-in, or held by effect of consignment to unit areas (for future drilling and development). This success has greatly influenced the movement to or interest in offshore areas, not only along the OCS of the United States but also worldwide. Industry's confidence in the possibility of developing prolific hydrocarbon deposits in progressively deeper water is evidenced by the leasing of 38 tracts (200,000 acres) for exploration and development where water is over 600 ft deep off the California coast, and several tracts offshore Louisiana approaching 600 ft in depth.

In the Federal offshore area (including validated State leases) 6,292 holes had been drilled as of November 1967, and 2,997 were producing hydrocarbons. From 1953 to 1967, 47 new fields were discovered in this area. The annual royalty value of crude oil, condensate, and gas produced from the Federal area of the Gulf of Mexico increased from $967,892 in 1953 to $132,849,922 in 1966; and the cumulative value to January 1967 is $615,053,412. In 1967 the average oil production rate from offshore completions was about 150 bpd, while the average for the total United States was about 15 bpd. There is approximately 500,000 bbl of proved oil reserves per offshore completion, and 55,000 bbl per onshore completion. At yearend 1967, the Gulf of Mexico had about 8 pct of the total United States proved crude oil reserves,

1 pct of the producing completions, 9 pct of the 90-day producing capacity, and 9 pct of the total production.

The attraction of petroleum industry capital to offshore areas may be attributed to several factors. Among the more important are discovery of sizable fields (of the 41 giant fields in Louisiana, 14 are offshore and six of the top 10 are offshore); the average success ratio for exploratory wells drilled in the Gulf of Mexico (26 pct success for offshore and 18 pct success for onshore); the size of the tracts being offered (about 5,000 acres); and the obtaining of acreage from a single owner.

Some industry experts regard the bonus investment as an indicator of future capital expenditure for drilling and production development. An average multiplier (10) for determining ultimate spending from bonus investment is 5. The major factors influencing this multiplier are the individual operator, nature of a prospect, wildcat success, distance from shore, and water depths. About $2.5 billion (this includes 1968 nominated sales) has been spent on bonuses. By applying the multiplier, an additional $10 billion outlay will be made eventually for exploration and development of leases acquired to May 1968.

From 1954 through 1966 annual Gulf of Mexico crude oil and condensate production increased steadily from less than 1.0 pct of the total U.S. domestic production to over 8 pct. This increase was at the expense of onshore production which had a growth rate of 1.5 pct per year while offshore had a 26 pct growth rate. The percentage of total annual U.S. expenditures spent for drilling and equipping offshore oil and gas wells increased from less than 1.0 pct of the total in 1953 to about 17.0 pct in 1965. The substantial capital investment in the development and production of Gulf of Mexico fields has reduced the expenditures for the onshore areas. For example, onshore seismic exploration activity has decreased steadily from 35,990 crew weeks in 1953 to 15,731 crew weeks in 1967, and the onshore annual footage drilled by the oil industry decreased from 198 to 133 million ft.

The projection of total Gulf of Mexico production to 1975 assumes the following: (1) Increased technology in both drilling and producing operations will allow operators to produce to the edge of the OCS, or in water depths up to 600 ft; (2) the Federal lease sales will continue at approximately the same rate as they have since 1954; (3) the demand for offshore crude oil, condensate, and gas continues as it has in the past; and, (4) the discovery rate and quality of discoveries continue as in the past. Also, the time lags of up to 5 years from lease to discovery dates and the 1,107,700 acres classified productive-shut-in (October 1967) provides a semiproven reserve of hydrocarbons during the forecast period.

Using the reasoning in these considerations it seems probable that the production from the Gulf of Mexico will continue to 1975 within the range shown in figure 19. The upper value represents a growth rate of 19 pct per year and would result in an annual production of 1,150 million bbl in 1975; the lower value represents a growth rate of 13 pct per year and would result

in an annual production of about 750 million bbl in 1975. Using an estimated domestic production (13) for oil and condensate in 1975 of 3.9 billion bbl, Gulf of Mexico production would be 20-30 pct of the total.

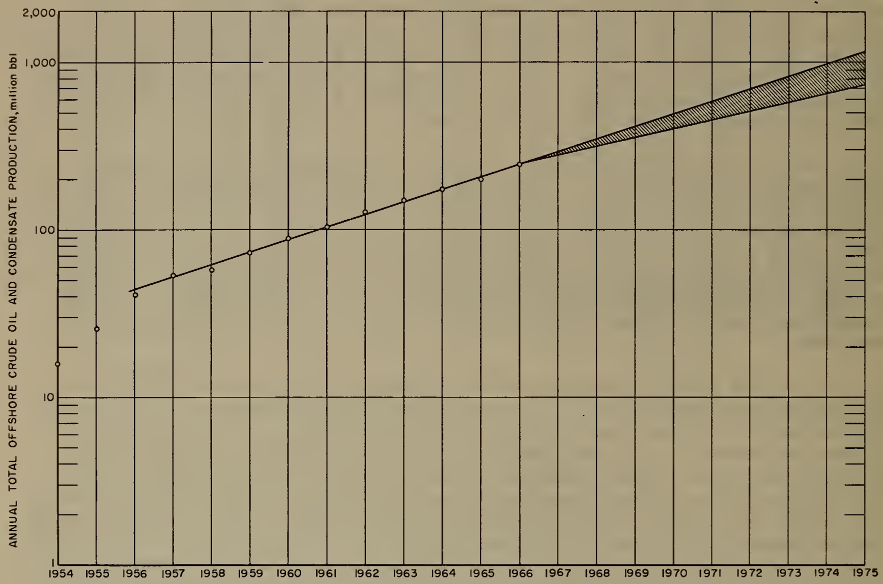


FIGURE 19. - Annual Gulf of Mexico Crude Oil and Condensate Production, 1954-66, and Projected Through 1975.

REFERENCES

1. American Association of Petroleum Geologists. Exploratory Drilling, 1953-1965. Frederick H. Lahee, v. 38, No. 6, June 1954, pp. 971-987; Frederick H. Lahee, v. 39, No. 6, June 1955, pp. 787-804; Frederick H. Lahee, v. 40, No. 6, June 1956, pp. 1057-1075; Graham E. Moody, v. 41, No. 6, June 1957, pp. 898-1005; B. W. Blanpied, v. 42, No. 6, June 1958, pp. 1125-1142; B. W. Blanpied, v. 43, No. 6, June 1959, pp. 1117-1138; B. W. Blanpied, v. 44, No. 6, June 1960, pp. 657-682; J. Ben Carsey, v. 45, No. 6, June 1961, pp. 701-727; J. Ben Carsey and Marion S. Roberts, v. 46, No. 6, June 1962, pp. 725-771; J. Ben Carsey and Marion S. Roberts, v. 47, No. 6, June 1963, pp. 889-934; Leo R. Newfarmer and E. L. Dillon, v. 48, No. 6, June 1964, pp. 749-777; Leo R. Newfarmer and E. L. Dillon, v. 49, No. 6, June 1965; pp. 634-660; E. L. Dillon and L. H. Van Dyke, v. 50, No. 6, June 1966, pp. 1114-1138.

2. American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continent Oil and Gas Association. Joint Association Survey of Industry Drilling Costs, 1953, 4 pp., table 3; 1955-56, 13 pp.; 1959, 14 pp., tables 36 and 37; 1960, 14 pp., tables 36 and 37; 1961, 15 pp., tables 36 and 37; 1962, 16 pp., tables 36 and 37; 1963, 16 pp., tables 36 and 37; 1964, 8 pp., tables 36 and 37; and 1965, 51 pp., tables 36 and 37.

3. Federal Reserve Bank of Dallas. Business Review. June 1968, p. 5.

4. Kliewer, Donald E. Editorial. World Oil, v. 163, No. 1, July 1966, p. 7.

5. Louisiana Department of Conservation. Secondary Recovery and Pressure Maintenance Operations in Louisiana, 1966 Report, 124 pp.

6. Louisiana Offshore Oil Scouts Association. Status of the Louisiana Offshore Oil Industry--Report of Offshore Drilling Units. Statistical Review of Events, 1959-67, 56 pp.

7. The Oil and Gas Journal. Annual Review--Forecast Issue, v. 51, No. 37, Jan. 26, 1953, p. 169; v. 52, No. 38, Jan. 25, 1954, p. 150; v. 53, No. 39, Jan. 31, 1955, p. 166; v. 54, No. 39, Jan. 30, 1956, p. 168; v. 55, No. 4, Jan. 28, 1957, p. 192; v. 56, No. 4, Jan. 27, 1958, p. 190; v. 57, No. 4, Jan. 26, 1959, p. 119; v. 58, No. 9, Feb. 29, 1960, p. 39; v. 59, No. 4, Jan. 23, 1961, p. 45; v. 60, No. 4, Jan. 22, 1962, p. 27; v. 61, No. 3, Jan. 21, 1963, p. 55; v. 62, No. 4, Jan. 27, 1964, p. 138; v. 63, No. 4, Jan. 25, 1965, p. 128.

8. _____. Rotary Rig Activity Dips Again. V. 61, No. 4, Jan. 28, 1963, p. 164; v. 65, No. 5, Jan. 30, 1967, p. 152.

9. _____. Move Is On to New Areas, Greater Depths, Larger Sizes. V. 64, No. 50, Dec. 12, 1966, p. 67.

10. The Oil and Gas Journal. Offshore Sale Won't Hurt Inland Drilling Much--This Year. V. 60, No. 20, May 14, 1962, p. 75.

11. _____. Shell Uses "Blending Shoe" to Install Offshore Riser. V. 15, No. 47, Nov. 20, 1967, p. 200.

12. Rigg, A. M., T. W. Childers, and C. B. Corley, Jr. A Subsea Completion System for Deepwater. J. Petrol. Technol., v. 18, No. 10, September 1966, pp. 1049-1055.

13. Vogely, William A., and Warren E. Morrison. Pattern of Energy Consumption in the United States. Pres. at World Power Conf., Tokyo, Japan, October 1966, 24 pp. (available for inspection at Dallas Office of Mineral Resources, Bureau of Mines, Dallas, Tex.)

14. Wilson, J. E. Economics of Offshore Louisiana. Pres. at Ann. Meet. of the Louisiana-Arkansas Division of Mid-Continent Oil and Gas Association, Sept. 12, 1967, 27 pp. (available for inspection at the Dallas Office of Mineral Resources, Bureau of Mines, Dallas, Tex.)

APPENDIX A.--CUMULATIVE AND 1967 OIL AND GAS PRODUCTION, OFFSHORE ALASKA (COOK INLET) AND CALIFORNIA

Field	Year discovered	1967 production: Crude oil, bbl	1967 production: Gas, Mscf	Cumulative, Jan. 1, 1968: Crude oil, bbl	Cumulative, Jan. 1, 1968: Gas, Mscf
ALASKA (Cook Inlet)					
Granite Point.......	1954	7,016,000	4,811,000	7,016,000	4,811,000
McArthur River......	1965	749,000	219,000	749,000	219,000
Middle Ground Shoal.	1962	7,654,000	3,197,000	10,336,000	4,406,000
Trading Bay.........	1965	727,000	705,000	729,000	705,000
CALIFORNIA					
Algeria.............	1962	5,000	464,000	58,000	1,767,000
Belmont.............	1948	4,273,000	5,737,000	18,203,000	23,456,000
Caliente............	....	-	4,285,000	-	15,821,000
Carpinteria.........	1966	3,404,000	2,612,000	4,317,000	3,079,000
Coal Oil Point......	1961	159,000	283,000	871,000	2,260,000
Conception..........	1961	888,000	614,000	18,587,000	11,943,000
Cuarta..............	1961	18,000	532,000	561,000	16,839,000
Elwood..............	1928	225,000	354,000	75,305,000	84,474,000
Elwood, South.......	1966	1,520,000	1,621,000	1,520,000	1,621,000
Gaviota.............	....	-	8,315,000	-	50,277,000
Huntington Beach....	1926	13,359,000	8,204,000	335,252,000	1/350,268,000
Molino..............	....	-	30,576,000	-	1/110,509,000
Montalvo, West......	....	167,000	284,000	4,482,000	1/5,194,000
Naples..............	....	-	-	-	20,815,000
Newport, West.......	1953	115,000	27,000	3,057,000	1,034,000
Rincon..............	1927	787,000	783,000	24,949,000	23,798,000
Seal Beach (Alamitos Area).............	1926	16,000	10,000	587,000	1/639,000
Summerland..........	1958	1,861,000	9,453,000	19,498,000	56,065,000
Torrance West Area2/............	1956	152,000	184,000	3,623,000	1/4,687,000
Venice Beach........	1966	409,000	434,000	409,000	1/434,000
Wilmington..........	1965	37,464,000	11,513,000	427,376,000	1/405,313,000

1/ Estimated.
2/ Combined with Torrance Main Area, 1966.

APPENDIX B.--LEASING PROCEDURES AND TERMS DESCRIBED IN SECTION 8 OF PUBLIC LAW 212

A. Oil and gas--competitive bidding.

1. Sealed bid.

   (a) Cash bonus with fixed royalty.
   (b) Royalty bid with fixed bonus.

2. Royalty not less than 12.5 pct (16-2/3 pct has been the OCS royalty to date).

3. Compact area--not exceeding 5,760 acres.

4. Term is 5 years and so long thereafter as oil or gas may be produced in paying quantities or drilling or well reworking operations, as approved by the Secretary, are conducted.

5. Rental as prescribed by the Secretary of the Interior at the time of offering the area for lease.

B. Sulfur--competitive bidding.

1. Sealed bid.

   (a) Cash bonus.

2. Area as determined by the Secretary.

3. Term is 10 years and so long thereafter as sulfur is produced in paying quantities or drilling conducted.

4. Royalty as determined by the Secretary but not less than 5 pct of the gross production or value at the wellhead.

5. Rental as prescribed by the Secretary.

C. Other minerals--competitive bidding.

1. Sealed bid.

2. Area as prescribed by the Secretary at the time of offering the area for lease.

3. Term as prescribed by the Secretary at the time of offering the area for lease.

4. Royalty as prescribed by the Secretary at the time of offering the area for lease.

5. Rental as prescribed by the Secretary at the time of offering the area for lease.

The BLM has been designated to administer leasing regulations on the public lands of the OCS. The Code of Federal Regulations (CFR), Title 43, part 3380, describes the functions of the BLM in regard to these lands. Official maps of the OCS are prepared by the BLM, and normally are made to conform as nearly as possible to the method of tract designation used by the adjoining State. The area of a tract offered for lease may not exceed 5,760 acres.

The Secretary of the Interior was authorized by the OCS Lands Act to issue leases for minerals in submerged lands of the OCS. Helium ownership rights, however, are exclusively for the U.S. Government. Leases are issued at the Secretary's discretion. The USGS and BLM furnish recommendations to the Secretary in the lease sale planning process. Normally, when enough interest has been expressed in leasing any particular offshore area, a call for nominations in a specified area is made. However, from time to time the Director of BLM may issue calls for the submission of requests for mineral lease offerings in specified areas. Requests to bid on specified areas should be made to the Director of BLM, Washington, D.C., with a copy furnished to the appropriate Oil and Gas Supervisor of the USGS. Specific tracts to be offered for lease from within the area opened for nominations are selected by the BLM and USGS. Then a notice of lands for lease is published in the Federal Register and other publications (the Federal Register is the official publication) at least 30 days prior to the sale. The notice establishes the place, date, and the hour for opening of the sealed bids. The notice may also set special conditions applicable, and these may become part of the terms of the leases.

Further, a separate bid must be submitted for each desired tract, and must be accompanied by one-fifth of the bonus. This amount may be in the form of a certified or cashiers check, bank draft, money order, or cash. If an individual is bidding, a statement of citizenship must be included; whereas if the bidder is an association or organization, proof of organization (or appropriate reference to same if already on file with the BLM), and authority for person or persons officiating for the group is required.

Leases are awarded to the highest qualified bidder if it is determined by the BLM that it would be in the public interest to do so. These contracts specify an agreement for a 5-year term, and are maintained in force as long as oil or gas may be produced in paying quantities, or approved drilling or reworking operations are conducted. In the event of a high-bid tie, 15 days are allowed in which to accept the lease jointly or the bid is considered rejected. If the United States does not accept the high bid within 30 days after the date on which the bids were opened, it is considered rejected and the deposit returned. If the lease is awarded, the balance of the bonus (four-fifths), and the stated first year rental are due within 30 days. Failure of the lessee to return the leases, balance of bonus and rental within the prescribed time results in forfeiture of the bonus submitted with the bid. Lessee or operator surety bonds of $15,000 must be furnished for each lease

acquired; however, this is not necessary on each lease received if a $100,000 surety bond has been posted with the BLM, or supplied at the time of completion of issuance of lease. As stated in Section A, subpart 1b of this appendix, the bid may be on the basis of royalty with fixed bonus. Although this procedure of royalty bidding is permitted under the law, all leasing to date has been by bonus bidding.

Leases normally become effective on the first day of the month following the bid openings. However, upon request, the lease may be made effective retroactive to the first day of the month in which the bid opening was held. Drilling, production, or reworking of a well directionally drilled under a tract from an adjoining tract maintains the lease.

Prescribed rental is due in advance on the first day of the lease-year. Specified minimum royalty is to be paid at the end of the lease-year in which a discovery was made. Royalty on production is paid on a monthly basis. Payments of royalty and rental are made to the United States through the regional Oil and Gas Supervisor of the USGS, and filing charges, bonuses, and first year rental are made to the appropriate BLM field office (unless otherwise directed by the Secretary).

The New Orleans BLM office is the office of record for leases and all assignments and relinquishments effecting record title must be filed there for approval or acceptance. Correspondence should be to: Manager, Outer Continental Shelf Land Office, Bureau of Land Management, P.O. Box 53226, New Orleans, La. 70150. All accrued rental and royalty must be paid; however, and well or other structures abandoned to the satisfaction of the Oil and Gas Supervisor of the USGS.

The USGS administers the regulations pertaining to oil, gas, and sulfur operations in the OCS. These functions include the regulating of drilling and production, rental and royalty collection (an exception is noted earlier), field hearings and rules, well and other structure abandonment, and other duties. Detailed information on the USGS role in the offshore areas may be found in Title 30, part 250, Chapter II, of the CFR. Other functions of the USGS may be found in Title 30, part 3380, Chapter II, of the CFR.

The OCS Lands Act authorizes the Secretary to prescribe rules and regulations applicable to operations conducted under a lease issued or maintained under the provisions of the Act. The USGS is charged with enforcing the prescribed rules and regulations to prevent waste and conserve natural resources of the OCS, including the suspension of production if necessary.

No royalty or rental is due during a suspension of production authorized by the Director of the USGS. However, should the lessee request suspension and approval is given, the lease is effectively held inactive (does not expire), but payment of royalty or rental continues. Regardless of who calls for suspension no expiration occurs, but in fact the lease is extended for a period generally equal to the time of suspension. A lessee may be granted a maximum of 5 years of suspension at any given time when production is from a gas well, shut in for lack of transportation.

Provisions are further specified in the CFR for the Director of the USGS to allow a reduction of specified rental or royalty rates when continued operation under the original terms are shown to be impractical. In such cases detailed statements of expenses and income must be appropriately filed.

Subsurface storage of hydrocarbons to avoid waste and promote conservation is permitted, with approval of the Secretary, when it can be shown that no undue interference with operations under existing leases will result. Any lease of an area used for the storage of oil or gas shall not be deemed to expire during the period of such storage and so long thereafter as oil or gas not previously produced is produced in paying quantities or approved drilling or reworking operations are being conducted.

APPENDIX C.--SALIENT DATA FOR GULF

TABLE C-1. - Louisiana

Reference No.	Field	Block	Zone 1/	District and number	Lease date	Discovery date	First production	Approximate water depth, ft	1966 production: Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf
1	Bay Marchand........	2	ICL, 1-2	Houma, No. 1	3/48	3/49	3/49	35	26,813,484	40,612	14,925,143	6,068,474
2	Breton Sound........	1	ICL	New Orleans, No. 4	3/54	5/55	5/60	5	15,182	149	-	214,673
3	...do...............	12	1	...do..............	8/65	10/66	Shut in	(2/)	1,046	-	-	-
4	...do...............	18	ICL	...do..............	6/63	8/63	4/65	15	136,318	-	118,347	-
5	...do...............	20	ICL	...do..............	8/51	7/53	7/53	15	2,212,327	798	910,524	2,102,818
6	...do...............	31	ICL	...do..............	10/64	8/66	11/66	(2/)	6,072	-	3,163	-
7	...do...............	32	ICL	...do..............	6/47	8/49	8/49	10	30,784	663	9,233	843,753
8	...do...............	36	ICL	...do..............	6/47	2/48	1/54	5	-	613	-	6,461,209
9	...do...............	49	1	...do..............	2/60	3/61	12/63	20	-	-	-	-
10	...do...............	53	1	...do..............	4/61	3/62	4/62	10	97,817	-	95,100	-
11	Chandeleur Sound....	41	ICL	...do..............	4/53	5/54	5/58 Abandoned	5	-	-	-	-
12	...do...............	69	ICL	...do..............	3/54	6/54	6/62	5	-	-	-	235,635
13	Creole (Offshore)...	...	1	Lake Charles, No. 3	-	3/38	4/38	5	221,502	-	131,344	-
14	East Cameron........	4	1	...do..............	3/48	8/55	4/58	20	-	147,552	-	6,507,652
15	...do...............	17	1-2-3	...do..............	7/54	3/55	11/58	20	247,615	37,479	708,142	3,881,092
16	...do...............	24	2	...do..............	8/59	12/64	5/65	35	-	5,112	-	356,286
17	...do...............	49	3	...do..............	6/47	9/55	7/58	50	-	-	-	-
18	...do...............	62	3-4	...do..............	7/47	1/56	6/58	55	-	-	-	8,556,150
19	...do...............	64	2-3	...do..............	6/47	6/57	7/58	50	74,010	1,246,774	75,892	67,835,139
20	...do...............	71	3	...do..............	7/47	10/54	7/58	50	-	21,742	-	9,529,598
21	...do...............	89	4	...do..............	3/62	8/65	10/66	60	-	1,225	-	810,335
22	...do...............	160	4	...do..............	7/55	9/56	Shut in	80	-	-	-	-
23	...do...............	224	4	...do..............	3/62	12/66	Shut in	110	-	-	-	960
24	Eloi Bay............	...	ICL	New Orleans, No. 4	11/52	12/53	1/54	(2/)	856,849	4,523	905,656	1,137,103
25	Eugene Island.......	8	1	Lafayette, No. 2	3/59	10/59	Shut in	5	-	-	-	-
26	...do...............	18	1	...do..............	11/48	6/54	11/54	5	2,738,363	45,716	4,868,318	2,641,777
27	...do...............	32	2-3	...do..............	8/48	12/49	8/56	10	1,284,696	3/276,010	2,725,409	36,726,020
28	...do...............	45	3	...do..............	11/46	11/48	1951	20	618,793		551,880	484,492
29	...do...............	53	3	...do..............	10/54	7/57	12/64	20	-	17,595	-	1,248,674
30	...do...............	77	3	...do..............	10/54	5/56	2/66	20	88,477	104,216	129,621	6,111,316
31	...do...............	100	3	...do..............	2/60	8/60	11/60	25	871,020	23,896	3,440,898	523,836
32	...do...............	110	3	...do..............	8/45	7/49	1952	20	222,620	-	343,441	141,593
33	...do...............	126	3-4	...do..............	8/45	7/49	1950	35	5,248,065	561	4,625,269	84,901
34	...do...............	128	4	...do..............	8/45	6/55	8/55	55	2,661,834	40,558	4,117,492	877,073
35	...do...............	175	4	...do..............	10/54	7/56	5/58	80	57,605	-	17,391	-
36	...do...............	184	4	...do..............	10/54	3/56	5/60	70	-	40,214	-	2,185,016
37	...do...............	188	4	...do..............	10/54	10/56	10/56	65	2,203,089	-	2,720,676	2,720
38	...do...............	198	4	...do..............	10/54	12/58	2/66	95	85,174	354,222	87,422	8,005,352
39	...do...............	208	4	...do..............	7/55	9/58	3/60	90	654,791	254	656,463	-
40	...do...............	238	4	...do..............	3/62	2/64	12/64	125	782,049	-	694,492	-
41	...do...............	276	4	...do..............	3/62	9/64	6/66	160	691,335	-	890,878	-
42	Grand Isle..........	16	1-2	Houma, No. 1	9/46	11/48	5/59	45	12,781,630	7,461	12,237,525	616,781
43	...do...............	18	2	...do..............	9/46	8/48	8/48	45	1,733,537	-	759,282	-
44	...do...............	25	1	...do..............	3/59	5/61	5/66	35	-	7,918	-	1,541,789
45	...do...............	41	3	...do..............	4/47	9/64	10/65	90	584,635	-	1,017,142	-
46	...do...............	43	2-3	...do..............	6/48	10/56	11/61	130	7,078,879	23,330	7,040,319	1,059,717
47	...do...............	47	3	...do..............	4/47	12/55	4/56	90	3,841,508	235,367	8,598,238	7,524,189
48	...do...............	82	4	...do..............	3/62	6/65	6/66	200	3,560	-	5,703	-
49	Half Moon Lake......	...	ICL	New Orleans, No. 4	11/52	5/63	9/63	(2/)	197,195	-	115,169	-
50	Hog Bayou (Offshore)	...	1	Lake Charles, No. 3	7/47	10/48	1952	5	49,166	241,917	-	9,825,518
51	Lake Athanasio......	...	ICL	New Orleans, No. 4	7/52	6/54	6/54 Shut in	(2/)	-	-	-	-

See footnotes at end of table.

OF MEXICO OIL AND GAS FIELDS TO 1967

oil and gas field data

Cumulative production, Jan. 1, 1967				Wells, February 1968				Production transportation 4/	Ref. erence No.
Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf	Oil	Gas	Dry	Other		
179,003,728	482,073	102,692,917	45,452,172	244	-	34	65	Two 4-in., 6-in., 6-in.(proposed), two 10-in. F/L's to shore; 6-in, 16-in. P/L's to shore.	1
67,095	1,307	54,609	674,456	(5/)	(5/)	(5/)	(5/)	-	2
1,046	-	-	-	(5/)	(5/)	(5/)	(5/)	-	3
257,208	-	284,458	-	(5/)	(5/)	(5/)	(5/)	12-in. P/L to Breton Sound 36; barge.	4
10,389,655	68,957	4,742,763	23,569,801	(5/)	(5/)	(5/)	(5/)	Barge.	5
6,072	-	3,163	-	(5/)	(5/)	(5/)	(5/)	Do.	6
499,815	4,760	579,122	4,201,412	(5/)	(5/)	(5/)	(5/)	Do.	7
-	28,353	-	85,078,536	(5/)	(5/)	(5/)	(5/)	12-in. P/L to shore.	8
-	1,692	-	54,613	(5/)	(5/)	(5/)	(5/)	-	9
273,424	-	304,885	-	(5/)	(5/)	(5/)	(5/)	Barge.	10
-	2,307	-	3,879,419	(5/)	(5/)	(5/)	(5/)	-	11
-	28	-	940,151	(5/)	(5/)	(5/)	(5/)	-	12
5,541,036	4,661	5,335,734	883,163	(5/)	(5/)	(5/)	(5/)	-	13
-	1,161,002	-	55,434,251	-	-	2	-	12-in. P/L to shore.	14
482,173	908,809	2,215,156	53,816,807	2	-	3	1	Two 12-in. P/L to shore; barge.	15
-	9,859	-	779,449	-	1	1	-	-	16
-	703	-	50,251	(5/)	(5/)	(5/)	(5/)	-	17
-	5,070	-	67,860,017	-	4	11	10	16-in. P/L to platform in East Cameron 62-64 fields area; 26-in. P/L to shore from platform services both fields, and West Cameron 192 field.	18
94,644	5,674,224	96,931	292,788,535	-	36	8	4	Two 12-in., 16-in. P/L's to platform; barge; (26-in. P/L, see East Cameron 62).	19
-	319,909	-	92,984,375	-	-	4	7	12-in. P/L to Vermilion 46 field; 16-in. P/L to platform in East Cameron 62-64 fields area; barge.	20
-	1,225	-	810,335	-	4	10	5	6-in. P/L to East Cameron 71 (proposed); barge.	21
175	-	224	2,400	-	-	4	7	-	22
-	-	-	960	-	-	5	1	-	23
3,304,679	37,338	3,749,117	8,880,628	(5/)	(5/)	(5/)	(5/)	Barge.	24
-	46	-	3,622	(5/)	(5/)	(5/)	(5/)	-	25
22,054,986	270,734	41,975,955	17,174,281	36	2	16	9	10-in. P/L to shore; barge.	26
7,935,289	6/4,885,248	22,432,171	523,798,501	17	12	12	6	20-in. P/L to shore; barge.	27
5,110,380	47,877	4,898,435	14,365,826	7	-	12	3	12-in. P/L to shore; 14-in. P/L to Eugene Island 32; barge.	28
-	30,578	-	2,244,614	-	1	3	1	4½-in. P/L to Eugene Island 32 via tie-in to 14-in. P/L.	29
88,477	104,216	129,621	6,111,316	1	3	8	1	-	30
5,319,570	50,662	12,178,763	1,086,969	11	3	12	8	4-in. F/L to Eugene Island 45 via tie-in to 12-in. F/L; 6-in. F/L to shore via tie-in to 20-in. F/L; barge.	31
1,819,470	381,363	3,342,826	16,700,784	1	-	39	22	Barge.	32
46,031,075	101,732	36,944,809	4,106,473	65	-	22	25	12-in. F/L to Eugene Island 45; 16-in. P/L to Ship Shoal 28 (pickup at Ship Shoal 32); barge.	33
20,467,846	363,976	32,205,872	8,129,592	40	1	27	27	10-in. F/L to Eugene Island 126; 16-in. P/L to Eugene Island 126; 20-in., 24-in. (proposed) P/L's to shore; barge.	34
1,663,363	218	2,645,857	4,929	2	-	18	15	Barge.	35
34,221	414,968	84,180	18,162,903	2	-	9	6	14-in. P/L to Eugene Island 128; barge.	36
9,343,728	245	10,723,113	150,074	39	-	30	14	12-in. F/L to Eugene Island 175 (proposed); 12-in. P/L to Eugene Island 77 (proposed); 16-in. P/L to Ship Shoal 28 (proposed); barge.	37
85,174	354,222	87,422	8,005,352	3	7	8	3	6-in. P/L to Eugene Island 175; 20-in. P/L to shore (proposed); barge.	38
6,555,264	16,096	4,643,996	251,390	22	-	24	25	6-in. P/L to Eugene Island 126; barge.	39
1,023,276	-	942,149	-	18	-	8	10	-	40
691,491	-	890,878	-	48	-	23	13	12-in. P/L to Eugene Island 188 (proposed); barge.	41
65,761,886	95,757	48,007,230	5,206,206	162	1	83	77	10-in., 16-in. F/L and 12-in. P/L to shore; 6-in., two 10-in. F/L's to Grand Isle 18.	42
23,704,321	-	11,515,550	-	23	-	19	26	6-in. F/L to Grand Isle 16; 10-in. P/L to shore.	43
-	7,985	-	1,556,789	(5/)	(5/)	(5/)	(5/)	Barge.	44
715,579	-	1,226,091	-	11	-	5	3	6-5/8-in. F/L to Grand Isle 47; barge.	45
15,236,266	28,657	15,180,643	1,337,717	55	-	17	36	10-in. P/L to West Delta 73; 16-in. F/L to shore (proposed); 20-in. P/L to shore; barge.	46
34,619,192	1,482,359	56,556,413	35,359,852	33	2	15	8	12-in. F/L to West Delta-Grand Isle 43; 12-in. F/L to shore; 12-in. P/L to Bay Marchand 2; barge.	47
3,560	-	5,703	-	-	-	4	1	-	48
806,511	-	582,271	-	(5/)	(5/)	(5/)	(5/)	Barge.	49
115,366	766,343	6,603	52,296,899	(5/)	(5/)	(5/)	(5/)	-	50
43,221	-	25,612	-	(5/)	(5/)	(5/)	(5/)	-	51

TABLE C-1. - Louisiana oil

Reference No.	Field	Block	Zone[1/]	District and number	Lease date	Discovery date	First production	Approximate water depth, ft	1966 production: Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf
52	Lighthouse Point....	...	1-2	Lafayette, No. 2	2/36	12/58	11/64	10	56,698	129,999	417,545	8,120,676
53	Main Pass..........	6	1-2	New Orleans, No. 4	4/61	1/62	11/63	30	977,190	-	491,631	-
54	...do..............	11	ICL	...do..............	4/62	9/62	9/62	(2/)	-	-	-	-
55	...do..............	12	ICL	...do..............	3/59	12/59	2/61	(2/)	-	-	-	-
56	...do..............	23	ICL	...do..............	2/54	6/54	Abandoned	5	-	-	-	-
57	...do..............	24	ICL	...do..............	10/53	12/53	1/54	5	29,676	-	32,692	-
58	...do..............	25	ICL	...do..............	5/54	3/55	3/55	10	41,923	-	6,866	-
59	...do..............	35	ICL	...do..............	5/51	8/51	1952	5	4,303,077	31,587	2,871,749	1,574,781
60	...do..............	41	2-3	...do..............	8/47	1/57	4/57	50	8,666,437	-	9,427,243	4,263,001
61	...do..............	45	2	...do..............	8/47	9/57	Shut in	25	-	-	-	-
62	...do..............	46	1-2	...do..............	5/55	9/56	10/58	25	276,101	61,996	820,583	2,471,174
63	...do..............	47	1	...do..............	8/47	7/55	3/58	15	-	128,222	-	10,439,286
64	...do..............	69	1-2-3	...do..............	8/47	8/48	8/48	35	11,351,482	6,222	9,227,997	11,365,232
65	Mound Point.........	...	1	Lafayette, No. 2	2/36	8/58	12/59	5	221,555	8,784	139,365	2,183,047
66	Pass Wilson.........	...	ICL	Houma, No. 1	7/58	9/58	10/60	5	208,814	18,380	185,053	1,231,481
67	Rabbit Island.......	...	1	Lafayette, No. 2	2/36	6/42	7/63	5	866,803	-	705,366	-
68	Ship Shoal..........	28	2	Houma, No. 1	9/46	7/49	8/60	10	-	3,377,155	-	98,265,864
69	...do..............	32	2-3	...do..............	9/46	11/47	9/59	15	58,669	86,748	14,005	3,517,521
70	...do..............	67	1	...do..............	6/48	11/55	2/56	45	-	-	-	-
71	...do..............	72	2	...do..............	9/46	8/48	1951	25	174,066	25,281	-	2,145,116
72	...do..............	107	3	...do..............	9/46	2/57	4/61	20	3,842,507	-	3,944,127	-
73	...do..............	113	3-4	...do..............	9/46	7/55	3/58	40	763,285	5,358	876,726	359,107
74	...do..............	139	3	...do..............	7/55	9/57	4/62	60	-	-	-	-
75	...do..............	154	4	...do..............	10/54	8/55	8/55	50	1,652,144	-	1,009,074	165,500
76	...do..............	169	3-4	...do..............	2/60	9/60	10/61	45	74,726	7,499	46,041	867,231
77	...do..............	176	4	...do..............	7/55	11/56	2/60	100	1,256,822	-	1,238,023	-
78	...do..............	208	4	...do..............	3/62	7/62	6/63	95	3,506,092	-	3,153,026	-
79	...do..............	274	4	...do..............	3/62	5/65	2/66	205	287,194	-	470,775	-
80	South Marsh Island..	6	4	Lafayette, No. 2	3/62	9/62	2/64	60	1,357,264	-	1,623,121	-
81	...do..............	23	4	...do..............	2/60	8/60	6/62	70	889,420	964,759	4,215,733	35,079,978
82	...do..............	27	4	...do..............	3/62	12/65	9/66	90	53,897	-	35,060	-
83	...do..............	48	4	...do..............	2/60	3/61	1/66	95	-	153,732	-	9,768,328
84	...do..............	73	4	...do..............	3/62	12/63	12/64	130	1,635,534	-	2,166,347	-
85	South Pass..........	5	1	New Orleans, No. 4	9/54	5/55	11/61	5	-	-	-	-
86	...do..............	6	1	...do..............	9/54	1/55	8/55	5	63,711	-	198,729	-
87	...do..............	21	1	...do..............	2/55	5/56	9/57	5	-	-	-	-
88	...do..............	24	1	...do..............	4/47	4/50	5/50	5	11,275,340	-	13,080,885	560,039
89	...do..............	26	1	...do..............	4/47	6/57	12/57	40	-	-	-	643,084
90	...do..............	27	1-2	...do..............	4/47	8/54	8/54	70	20,104,617	135,746	37,201,342	17,832,473
91	...do..............	30	1	...do..............	2/55	6/55	10/57	40	-	-	-	940,262
92	...do..............	42	1	...do..............	7/54	4/56	5/58	70	-	-	-	522,569
93	South Pelto.........	20	2-3	Houma, No. 1	9/46	8/51	3/55	20	1,295,548	33,464	2,066,143	1,729,274
94	...do..............	23	3-4	...do..............	3/62	7/62	5/63	60	535,753	-	675,678	-
95	Tiger Shoal.........	...	2	Lafayette, No. 2	2/36	7/58	4/60	10	1,116,258	304,152	1,378,004	22,829,575
96	Timbalier Bay.......	...	1-2	Houma, No. 1	-	1963	1/64	5	12,700,632	18,716	17,168,524	-
97	Timbalier, South....	8	1	...do..............	1/64	3/65	3/65	20	4,173	-	5,221	-
98	...do..............	34	2	...do..............	4/47	3/49	Shut in	50	-	-	-	-
99	...do..............	52	3	...do..............	5/48	9/50	Shut in	60	-	-	-	-
100	...do..............	54	3	...do..............	4/47	5/55	4/56	65	491,211	328,044	486,120	11,386,492
101	...do..............	86	3	...do..............	7/55	12/56	9/58	90	22,998	24,081	13,810	418,166
102	...do..............	131	4	...do..............	10/54	3/58	7/59	140	2,916,737	6,313	3,096,966	967,401
103	...do..............	135	3-4	...do..............	10/54	12/56	7/57	130	9,576,994	13,315	11,577,356	667,434
104	...do..............	172	4	...do..............	3/62	4/65	Shut in	100	-	-	-	5,100
105	...do..............	176	4	...do..............	3/62	4/63	3/64	140	535,626	-	933,868	-
106	...do..............	228	4	...do..............	3/62	8/65	Shut in	220	-	-	-	-

See footnotes at end of table.

and gas field data--Continued

Cumulative production, Jan. 1, 1967				Wells, February 1968				Production transportation[4/]	Reference No.
Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf	Oil	Gas	Dry	Other		
56,698	296,365	417,545	20,139,207	(5/)	(5/)	(5/)	(5/)	10-in., 30-in. F/L to shore (see Tiger Shoal and Mound Point fields).	52
1,306,651	-	629,083	-	5	2	2	3	24-in. P/L to shore (proposed); barge.	53
5,663	-	6,051	-	(5/)	(5/)	(5/)	(5/)	-	54
250,531	1,163	167,118	1,960,826	(5/)	(5/)	(5/)	(5/)	-	55
5,474	-	12,806	-	(5/)	(5/)	(5/)	(5/)	-	56
722,916	1,676	407,358	507,698	(5/)	(5/)	(5/)	(5/)	Barge.	57
715,026	-	166,301	-	(5/)	(5/)	(5/)	(5/)	Do.	58
51,379,271	212,756	37,404,667	18,395,615	(5/)	(5/)	(5/)	(5/)	-	59
14,453,717	8	14,923,569	14,849,015	151	14	26	14	6-in. F/L to Main Pass 69; 12-in. P/L to Mississippi; 14-in. P/L to shore.	60
1,463	-	2,535	-	(5/)	(5/)	(5/)	(5/)	-	61
1,921,064	761,622	3,949,049	12,315,738	(5/)	(5/)	(5/)	(5/)	8-in. P/L to shore; barge.	62
729,978	1,089,740	3,832,177	88,566,955	(5/)	(5/)	(5/)	(5/)	Barge.	63
102,057,467	89,865	87,110,731	82,212,106	-	-	2	-	10-in. F/L to shore.	64
1,833,991	8,784	1,069,241	2,183,047	(5/)	(5/)	(5/)	(5/)	8-in. liquid F/L to shore via tie-in 10-in. liquid F/L from Tiger Shoal; 16-in. F/L to shore via tie-in 30-in. Tiger Shoal F/L.	65
1,652,199	87,903	1,343,100	5,460,206	(5/)	(5/)	(5/)	(5/)	Barge.	66
1,540,277	-	1,027,792	5,819	(5/)	(5/)	(5/)	(5/)	Do.	67
97	9,203,370	-	268,185,380	-	29	3	15	Two 16-in. P/L to shore; 16-in., 20-in. P/L's to shore (proposed); barge.	68
905,914	415,563	149,530	11,477,484	2	6	14	7	6-in. P/L (see Eugene Island 126); barge.	69
85,899	14,499	99,036	264,667	(5/)	(5/)	(5/)	(5/)	-	70
3,478,881	230,602	2,607,330	16,134,602	3	5	10	6	14-in. P/L to Ship Shoal 28; barge.	71
16,943,485	-	16,426,503	-	35	-	15	3	Barge.	72
1,689,736	74,692	2,187,606	4,548,256	26	-	24	12	6-in. P/L to Ship Shoal 72; barge.	73
896,336	65	3,232,316	1,570	-	-	8	8	-	74
14,236,805	-	6,842,969	224,492	34	-	57	27	Barge.	75
520,682	50,281	326,211	4,077,578	1	3	13	25	10-in. P/L to Ship Shoal 72.	76
6,150,946	-	5,303,691	-	20	-	12	15	6-in. F/L to Eugene Island 208; barge.	77
9,405,865	-	8,057,012	-	41	1	12	16	10-in. P/L to Ship Shoal 169 (proposed); barge.	78
287,355	-	470,775	-	12	-	16	14	Barge.	79
3,252,997	-	3,450,143	-	27	1	33	19	12-in. P/L to shore.	80
2,424,314	3,267,631	7,924,036	128,445,182	9	13	8	8	16-in. P/L to Eugene Island 128; 20-in. P/L to Eugene Island 128 (proposed); barge.	81
53,897	-	35,060	-	3	1	8	1	Barge.	82
-	153,732	-	9,768,328	-	8	18	24	16-in. P/L to South Marsh Island 23 (proposed); barge.	83
2,257,904	-	2,878,381	-	53	4	52	18	10-in. P/L to South Marsh Island 6 (proposed); 12-in. P/L to Eugene Island 175; 20-in. P/L to Eugene Island 198 (proposed); barge.	84
68,618	8,560	288,614	473,386	(5/)	(5/)	(5/)	(5/)	-	85
699,772	515,839	1,750,383	21,497,957	(5/)	(5/)	(5/)	(5/)	Barge.	86
-	-	-	3,310,361	(5/)	(5/)	(5/)	(5/)	-	87
195,510,178	787,238	225,683,732	27,215,705	(5/)	(5/)	(5/)	(5/)	Barge.	88
-	-	-	3,204,884	(5/)	(5/)	(5/)	(5/)	-	89
110,778,020	430,954	187,841,453	68,242,897	327	23	29	78	Three 8-in., two 12-in., 16-in. F/L's to shore.	90
-	-	-	12,131,968	(5/)	(5/)	(5/)	(5/)	-	91
-	-	-	6,173,318	(5/)	(5/)	(5/)	(5/)	-	92
5,265,383	114,981	11,866,453	6,941,398	28	4	28	8	8-in. P/L to Ship Shoal 72; barge.	93
1,649,395	-	1,945,615	-	11	-	14	3	-	94
5,496,906	374,533	5,556,377	28,141,845	(5/)	(5/)	(5/)	(5/)	10-in. liquid F/L, 30-in. F/L to shore (with tie-in from Lighthouse Point and Mound Point fields).	95
40,271,604	25,704	59,099,454	-	114	-	11	20	Two 6-in. F/L to shore; 10-in. P/L to shore.	96
4,173	-	5,221	614	(5/)	(5/)	(5/)	(5/)	-	97
172,949	-	89,973	-	-	-	21	5	-	98
34,340	-	40,583	-	(5/)	(5/)	(5/)	(5/)	-	99
2,350,400	1,700,365	2,294,346	41,556,900	7	9	19	29	10-in. P/L to Grand Isle 16 (proposed); 12-in. P/L to shore.	100
1,126,036	51,474	1,171,319	2,102,814	-	-	13	10	-	101
11,843,915	6,313	10,063,992	967,401	50	1	24	9	18-in. F/L to shore; 22-in. F/L to West Delta 41.	102
26,254,916	13,315	32,466,899	667,434	94	5	15	34	16-in. F/L to Timbalier, South 131; 22-in. F/L (proposed) to Timbalier, South 131.	103
-	-	-	8,903	-	-	8	6	-	104
983,523	-	1,733,356	-	27	-	26	27	14-in. F/L to Timbalier, South 135; barge.	105
-	-	-	189	-	-	1	1	-	106

TABLE C-1. - Louisiana oil

Reference No.	Field	Block	Zone[1/]	District and number	Lease date	Discovery date	First production	Approximate water depth, ft	1966 Production			
									Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf
107	Vermilion...........	14	1-2	Lafayette, No. 2	1/46	7/56	1/60	25	77	2,004,456	-	92,171,674
108	...do...............	16	1	...do...............	4/61	7/61	6/64	10	-	681,792	-	4,665,194
109	...do...............	39	2	...do...............	11/46	6/49	1951	40	-	236,553	-	51,167,642
110	...do...............	46	2	...do...............	11/46	12/56	12/60	30	-	123,823	-	9,613,880
111	...do...............	71	3	...do...............	11/46	11/48	10/59	15	-	12,249	-	3,105,514
112	...do...............	76	3	...do...............	6/47	4/49	11/58	25	-	59,414	-	41,837,543
113	...do...............	86	4	...do...............	5/48	2/58	9/59	40	-	70,044	-	3,289,248
114	...do...............	120	4	...do...............	10/54	7/57	4/58	70	217,218	-	146,990	-
115	...do...............	129	4	...do...............	2/60	5/61	7/63	65	-	42,054	-	1,638,413
116	...do...............	131	4	...do...............	2/60	8/60	10/63	55	-	305,215	-	16,368,785
117	...do...............	164	4	...do...............	10/54	1/57	4/64	90	51,876	-	25,840	-
118	...do...............	245	4	...do...............	3/62	6/62	11/65	125	1,707,370	-	1,316,071	-
119	...do...............	250	4	...do...............	3/62	4/63	10/66	140	37,545	-	28,629	-
120	West Cameron........	1	1	Lake Charles, No. 3	2/60	3/61	Shut in	5	-	-	-	-
121	...do...............	17	1-2	...do...............	4/62	9/62	1/66	20	-	250,857	-	36,173,640
122	...do...............	19	1	...do...............	1/65	8/65	Shut in	15	-	-	-	41,392
123	...do...............	33	1-2	...do...............	7/47	8/49	12/59	30	-	39,976	-	4,956,799
124	...do...............	40	2	...do...............	5/48	3/55	5/59	25	-	-	-	1,220
125	...do...............	45	2	...do...............	7/47	5/49	1950	30	358,652	211,857	1,533,269	18,048,751
126	...do...............	67	2	...do...............	3/48	5/58	5/60	30	-	207,174	-	8,499,243
127	...do...............	71	2-3	...do...............	9/46	12/55	6/65	40	37,656	237,312	130,293	16,293,095
128	...do...............	110	4	...do...............	6/47	5/54	8/58	40	36,358	62,898	402,427	6,938,234
129	...do...............	149	4	...do...............	6/47	9/49	7/61	40	-	29,564	-	19,961,908
130	...do...............	180	4	...do...............	2/60	8/61	12/65	50	40,405	76,622	23,665	7,442,283
131	...do...............	192	4	...do...............	11/48	7/54	7/58	55	195,747	238,867	317,743	34,813,439
132	West Delta..........	27	1-2	New Orleans, No. 4	11/46	11/49	5/60	20	1,373,318	5,568,302	792,215	183,213,492
133	...do...............	30	1-2	...do...............	11/46	12/54	2/63	40	20,851,186	255,558	19,030,997	12,617,239
134	...do...............	41	3	...do...............	3/62	10/64	11/64	80	3,620,966	-	6,080,877	-
135	...do...............	52	ICL	...do...............	4/47	5/54	7/66	(2/)	518,074	8,205	497,251	129,219
136	...do...............	53	ICL, 1	...do...............	4/47	7/53	8/53	5	612,707	174,987	596,381	6,859,834
137	...do...............	55	ICL, 1	...do...............	7/54	9/55	4/57	10	-	-	-	10,701,836
138	...do...............	56	1	...do...............	7/54	5/55	7/58	30	-	-	-	859,954
139	...do...............	58	2	...do...............	4/47	6/55	5/58	45	-	329,834	-	4,574,622
140	...do...............	59	2	...do...............	4/47	8/55	5/58	55	-	76,376	-	1,304,322
141	...do...............	73	3	...do...............	3/62	1/63	11/63	170	10,840,562	-	10,749,142	-
142	...do...............	83	ICL, 1	...do...............	9/54	11/56	1/57	5	2,121,436	1,491	3,016,059	88,278
143	...do...............	84	1	...do...............	7/54	6/55	6/55	45	293,546	6,272	671,897	125,309
144	...do...............	105	3	...do...............	2/60	8/64	8/65	235	1,701,043	-	2,169,641	-
145	...do...............	117	3	...do...............	3/62	6/63	11/63	210	-	-	-	-
146	...do...............	133	4	...do...............	3/62	2/66	Shut in 9/66	275	138,789	-	115,666	-
147	Wildcat.............	...	1	Lake Charles, No. 3	-	1966	-	-	238	-	-	-

1/ Inside Chapman Line denoted by ICL.
2/ Water depth shallow; not available.
3/ Includes 25,825 bbl of calculated theoretical condensate.
4/ Oil and/or gas flowline denoted by F/L. Oil and/or gas pipeline denoted by P/L.
5/ Data not available.
6/ Includes 172,479 bbl of calculated theoretical condensate.

Sources: Louisiana Department of Conservation. Annual Oil and Gas Reports.
U.S. Department of Commerce, Coast and Geodetic Survey.
U.S. Geological Survey, Gulf Coast Region.

and gas field data--Continued

Cumulative production, Jan. 1, 1967				Wells, February 1968				Production transportation4/	Reference No.
Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf	Oil	Gas	Dry	Other		
316	9,924,203	-	429,866,007	-	37	4	4	14-in., 16-in. P/L's, 20-in. F/L to shore; barge.	107
-	1,444,601	-	10,294,756	(5/)	(5/)	(5/)	(5/)	Barge.	108
-	3,275,273	-	619,563,635	-	17	2	3	8-in., 10-in. P/L's to shore.	109
3,667	376,812	3,355	26,986,886	-	8	-	3	16-in. P/L to shore; 4-in., 6-in. P/L tie-ins (see Vermilion 76 field); barge.	110
-	108,522	-	22,149,620	-	6	9	1	16-in. P/L to Vermilion 76.	111
-	657,559	-	315,604,338	-	25	10	3	16-in., 20-in. P/L's to shore (through Vermilion 46 with pickups); barge.	112
-	408,971	-	19,329,845	-	3	3	-	10-in. P/L to Vermilion 76.	113
2,833,751	-	2,421,689	-	5	1	13	6	Barge.	114
-	185,804	-	6,607,980	-	1	6	-	6-in. P/L tie-in (see Vermilion 131); barge.	115
-	1,096,811	-	51,099,453	-	9	5	-	16-in. P/L to Vermilion 76 (through Vermilion 129 with pickup); barge.	116
162,817	-	92,017	3,000	1	-	18	3	Barge.	117
1,718,835	-	1,324,459	-	22	-	29	5	Do.	118
37,545	-	28,629	-	1	-	7	9	Do.	119
-	16	-	200	(5/)	(5/)	(5/)	(5/)	-	120
-	250,857	-	36,173,640	1	8	-	1	6-in., 18-in. F/L's to shore.	121
-	-	-	41,392	(5/)	(5/)	(5/)	(5/)	-	122
95,382	349,076	52,884	25,433,725	-	3	2	2	3-in., 12-in., 20-in. P/L's to shore.	123
-	42,912	-	8,417,064	-	-	5	4	16-in. P/L to shore.	124
4,888,337	2,542,017	17,273,665	153,047,305	13	13	13	4	6-in., 8-in., 16-in. P/L's to shore; barge.	125
-	1,008,780	-	42,405,101	-	7	7	2	12-in. P/L to shore.	126
55,412	385,812	203,164	26,173,394	1	8	1	-	16-in. P/L to shore (proposed); barge.	127
323,070	511,002	2,795,074	70,016,536	2	8	3	4	16-in. P/L to West Cameron 40.	128
-	42,081	-	24,009,770	-	16	9	4	12-in. P/L to West Cameron 71 (proposed); barge.	129
40,455	76,622	24,172	7,442,283	1	10	2	13	12-in. P/L to West Cameron 192 (proposed); barge.	130
985,231	2,570,656	1,113,377	288,875,530	3	28	15	16	20-in. P/L to platform in East Cameron 62-64 fields area; barge.	131
7,447,767	9,468,860	4,897,404	315,746,099	7	12	8	9	6-in. F/L to West Delta 30; 12-in., 20-in., 26-in. F/L's to shore.	132
121,202,771	299,628	110,150,155	14,713,819	275	6	85	103	Two 6-in., 10-in. F/L's to shore; three 12-in. P/L's to shore.	133
5,884,209	-	8,927,060	-	38	-	8	3	8-in. F/L to West Delta-Grand Isle 43; 16-in. F/L to shore; 26-in. F/L through West Delta 30 to shore; barge.	134
5,981,609	52,816	7,171,979	1,017,863	(5/)	(5/)	(5/)	(5/)	-	135
6,467,418	4,102,041	7,021,780	67,065,508	(5/)	(5/)	(5/)	(5/)	-	136
-	101,905	-	51,743,707	(5/)	(5/)	(5/)	(5/)	-	137
-	622	-	3,796,800	-	-	3	1	-	138
-	2,158,976	-	28,832,352	-	6	3	5	12-in. P/L to platform in West Delta 54 to tie-in with P/L to shore.	139
157,044	1,295,529	1,445,986	16,520,406	-	1	2	2	12-in. P/L to West Delta 58.	140
18,738,228	100	17,167,116	5,741	116	-	8	13	12-in. P/L to Grand Isle 18; 16-in. F/L to Grand Isle 16.	141
17,711,384	245,729	34,911,492	7,717,032	(5/)	(5/)	(5/)	(5/)	-	142
2,980,153	6,272	8,026,287	125,309	(5/)	(5/)	(5/)	(5/)	-	143
1,776,594	-	2,216,614	-	39	2	12	13	12-in. P/L to West Delta 30 (through West Delta 64 and 73 fields); 18-in. P/L to shore (proposed).	144
726,407	-	902,041	-	6	-	12	20	4-in. F/L to West Delta 73; 10-in. F/L to West Delta 41 (proposed).	145
138,789	-	115,666	-	17	-	34	12	8-in. P/L to West Delta 105; 18-in. P/L to West Delta 105 (proposed).	146
238	173	-	3,122	(5/)	(5/)	(5/)	(5/)	-	147

TABLE C-2. - Texas oil and gas field data

Field	Tract or block	County and Railroad Commission District number	Lease date	Dis-covery date	First produc-tion	Approxi-mate water depth, ft	1966 production: Crude oil, bbl	Conden-sate, bbl	Casing-head gas, Mcf	Natural gas, Mcf
Brazos	405	Matagorda, No. 3	5/64	9/66	Shut in	35	-	-	(1/)	-
Do	440	..do	2/65	11/66	Shut in	50	-	-	(1/)	-
Do	446	..do	-	4/64	Shut in	50	-	-	(1/)	-
Do	519-S	..do	2/65	10/66	Shut in	35	-	-	(1/)	-
Caplen (4650 Miocene)	-	Galveston, No. 3	-	1939	6/65	10	2/8,239	-	(1/)	-
Chevron	-	Kleberg, No. 4	12/53	11/54	1954	50	103,543	88,197	(1/)	11,704,448
Cowtrap (2450 and 2700)	-	Brazoria, No. 3	-	2/53	1961	10	-	-	(1/)	-
Federal	288	Galveston, No. 3	2/60	2/64	1965	65	364,903	-	(1/)	37,801,189
Galveston	189	..do	-	4/55	4/55	55	885	-	(1/)	-
GOM	ST-83-S	..do	5/64	7/64	Shut in	15	-	-	(1/)	-
GOM (Frio 7800 and 8200)	ST-904	Nueces, No. 4	12/53	3/57	1963	50	-	40,291	(1/)	1,815,243
High Island	10-L	Jefferson, No. 3	12/53	3/55	1959	35	-	6,852	(1/)	1,860,580
Do	52	..do	11/54	12/59	Shut in	40	-	-	(1/)	-
Do	160	..do	2/60	6/61	Shut in	50	-	-	(1/)	-
Kain (G-3, G-7, G-12, H-1 Sd, Miocene L, and L Central)	-	Matagorda, No. 3	12/53	7/54	1959	10	-	-	(1/)	2,763,193
McFaddin Beach Dome	-	Jefferson, No. 3	-	12/56	Shut in	55	-	-	(1/)	-
Mustang Island	889	Nueces, No. 4	12/53	1/55	1956	30	-	113,942	(1/)	4,533,850
Sabine Pass (K-1 Miocene, 7200)	-	Jefferson, No. 3	-	10/58	1958	5	-	-	(1/)	-
Sargent, South (Miocene 3250 and 4100)	-	Matagorda, No. 3	-	1/56	1956	10	-	-	(1/)	312,344
Sprint (Marg)	-	Kleberg, No. 4	12/53	11/54	1958	10	-	1,743	(1/)	450,091

Field	Cumulative production, Jan. 1, 1967: Crude oil, bbl	Condensate, bbl	Casinghead gas, Mcf	Natural gas, Mcf	Wells, February 1968: Oil	Gas	Dry	Other	Production transportation 3/
Brazos	-	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Do	-	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Do	-	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Do	-	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Caplen (4650 Miocene)	13,306	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Chevron	2,979,926	1,099,532	(1/)	96,053,649	(4/)	(4/)	(4/)	(4/)	-
Cowtrap (2450 and 2700)	-	-	(1/)	1,288,740	(4/)	(4/)	(4/)	(4/)	-
Federal	364,903	-	(1/)	37,824,514	19	33	21	1	20-in. P/L to shore.
Galveston	28,313	-	(1/)	38,403	1	2	1	-	-
GOM	-	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
GOM (Frio 7800 and 8200)	-	160,296	(1/)	7,058,245	(4/)	(4/)	(4/)	(4/)	-
High Island	-	53,081	(1/)	13,366,951	(4/)	(4/)	(4/)	(4/)	10-in. F/L to shore.
Do	62,634	-	(1/)	-	3	2	3	-	4-in. F/L to shore.
Do	-	-	(1/)	-	-	16	11	-	16-in. P/L to shore.
Kain (G-3, G-7, G-12, H-1 Sd, Miocene L, and L Central)	-	315	(1/)	10,223,607	(4/)	(4/)	(4/)	(4/)	-
McFaddin Beach Dome	133,399	-	(1/)	-	(4/)	(4/)	(4/)	(4/)	-
Mustang Island	-	1,117,020	(1/)	33,011,932	(4/)	(4/)	(4/)	(4/)	-
Sabine Pass (K-1 Miocene, 7200)	-	-	(1/)	90,104	(4/)	(4/)	(4/)	(4/)	-
Sargent, South (Miocene 3250 and 4100)	-	-	(1/)	2,950,333	(4/)	(4/)	(4/)	(4/)	-
Sprint (Marg)	-	21,563	(1/)	4,110,850	(4/)	(4/)	(4/)	(4/)	-

1/ All gas production included in Natural Gas.
2/ Transferred from Caplen field, June 1965.
3/ Oil and/or gas flowline denoted by F/L. Oil and/or gas pipeline denoted by P/L.
4/ Data not available.

Sources: The Railroad Commission of Texas.
U.S. Department of Commerce, Coast and Geodetic Survey.
U.S. Geological Survey, Gulf Coast Region.

☆U. S. GOVERNMENT PRINTING OFFICE : 1969 O - 336-688

TPRR

IC bureau of mines information circular 8410

DESIGN OF DAMS FOR MILL TAILINGS

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

1969

DESIGN OF DAMS FOR MILL TAILINGS

By C. D. Kealy and R. L. Soderberg

* * * * * * * * * * * information circular 8410

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

Keały, Charles D

Design of dams for mill tailings, by C. D. Kealy and R. L. Soderberg. [Washington] U. S. Dept. of the Interior, Bureau of Mines [1969]

49 p. illus. (U. S. Bureau of Mines. Information circular 8410)

Includes bibliography.

1. Dams. 2. Tailings (Metallurgy). I. Soderberg, Roy L., jt. auth. II. Title. (Series)

TN23.U71 no. 8410 622.06173

U. S. Dept. of the Int. Library

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price 55 cents

CONTENTS

ILLUSTRATIONS

DESIGN OF DAMS FOR MILL TAILINGS

by

C. D. Kealy[1] and R. L. Soderberg[1]

ABSTRACT

The Bureau of Mines studied tailings disposal problems at mines throughout the United States to identify design principles that can be applied to all types of dams for mill tailings. Computer programs for stability analysis and phreatic waterline estimation are also reviewed in this circular, which presents the Bureau's recommendations for constructing effective, long-lasting tailings dams.

INTRODUCTION

More than ever, public opinion is demanding the design of stable embankments as part of tailings disposal systems to aid in abating air and water pollution. Even though many areas have no restrictions requiring industry to impound its tailings, great interest has been generated through universities, industry, and Government in developing sound engineering principles regarding disposal problems. In some areas, attempts are already being made to prevent mine operations from starting because of the probable damage to local esthetic values. Because abandoned disposal areas are the land owner's liability when the mine has been exhausted, and must be a paramount consideration of planning groups that look 50 years hence at land disposition requirements, disposal costs and methods have become a significant mine operations problem.

The Bureau of Mines initiated a project concerned with the design of a tailings disposal system through its Heavy Metals Program. The information gathered, which includes the best methods for construction of a stable structure, maintenance of water conservation, control of air and water pollution, and provision of adequate land reclamation, applies generally to the disposal of all conventional mill tailings. The solutions offered here are based on theoretical and technical data from field studies made throughout the United States and on the application of various soil mechanics techniques.

Over 30 mines were visited, and studies were made of recent advances in soil mechanics methods and applications. Some of the practices are currently part of the waste disposal technique for one or more of the mines visited.

[1]Mining engineer, Spokane Mining Research Laboratory, Bureau of Mines, Spokane, Wash.

Others are modifications of current soils engineering practices. While these construction principles can be applied to all types of mill tailings dams, each area, climate, and subsequent use requires some modification in the various design parameters. Due consideration to the various parameters will result in a stable, functional disposal system, constructed and maintained at reasonable cost.

PRECONSTRUCTION ENGINEERING

With any type of major dam construction a complete hydrology study, including a determination of the amounts of milling, domestic, and excess water, must be made for design purposes. Often this information is available at no cost from State and Federal water resource agencies. The design of the dam must allow for the total natural and artificial runoff, so that when the area is abandoned the water can pass through or around the dam without soil erosion or undesirable impoundment occurring. Any decant or bypass system required to move the water through or around the abandoned tailing dam should be designed so that maintenance cost is negligible. In this way the disposal system does not become a liability to either the mining company or the public.

Foundation investigation, the next critical area of study, can be accomplished through selective drill-hole soil sampling and testing. From this information, the geologic structure of the substrata can be predicted as well as basic foundation data (permeability, density, and shear strength values). In many cases, when the structure is failing, these substrata design values are needed before effective rectification can be made. Such information is inexpensive to obtain and worth the money expended, since it is applicable both to embankment stability and to the design of decant lines that are to be constructed in the base. Numerous failures that resulted simply because soil conditions under the original structure were not investigated, have led to liability suits. One reported failure caused an estimated loss of between $13 and $14 million from claims and damages, owing to either a lack of engineering or, more probably, the failure to follow the engineering design as specified. On the other hand, proper engineering can eliminate costly overdesign and superfluous safety factors.

SOIL SAMPLING AND TESTING FOR DESIGN PARAMETERS

When developing design data for embankment stability, the existing tailings structure as well as any tailings structure yet to be constructed must be considered. The data needed to determine the factor of safety that an existing structure has or will have with further deposition of tailings is obtained from in-place samples. These readily available, undisturbed samples can be obtained with numerous soil sampling tools (4).[2] It is distinctly advantageous to develop such data while the representative samples are available. After the sample has been extracted it is tested in the laboratory for the required design parameters, which are relative density, moisture, shear strength, consolidation, and permeability. Figures 1 through 4 show the laboratory apparatus.

[2] Underlined numbers in parentheses refer to items in the list of references preceding the appendixes.

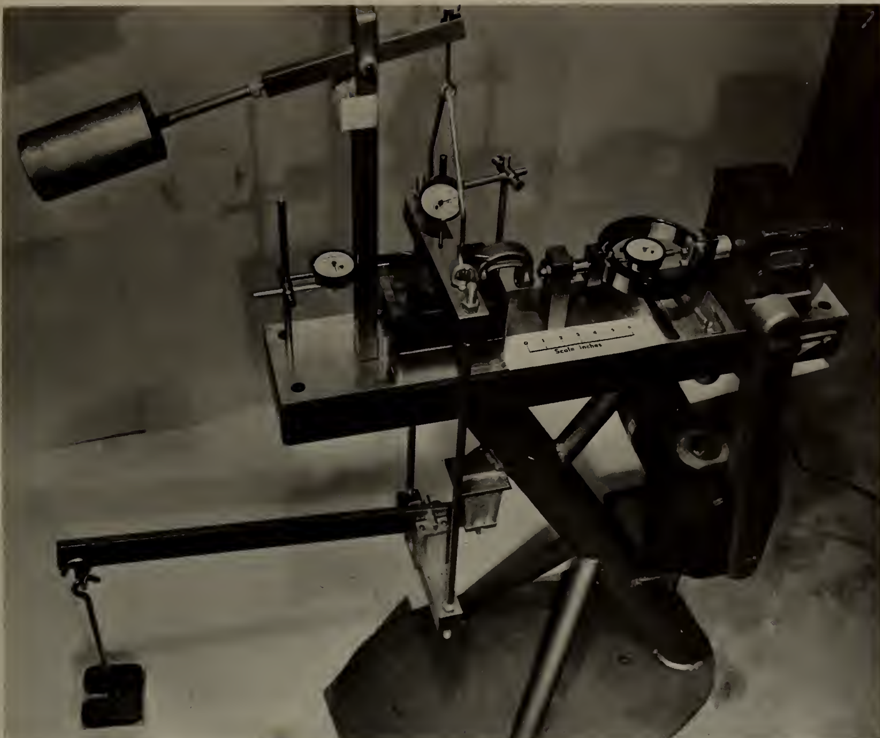


FIGURE 1. - Direct Shear Apparatus.

Access to an existing structure is also essential to the applicability of in-situ testing. Radioactive probes are being used to obtain density and moisture values in the field. Although in-situ vane shear testing has also been tried, such values have not been completely satisfactory. The standard penetrating test using the split-spoon samples has been used for comparing values and provides good guidelines simply because of the large volume of penetration data available. Necessary field measurements of the phreatic waterline and the general geometry of existing slopes are easily obtained for use in basic stability calculations.

A combination of experience with existing ponds of the same type and/or simulated undisturbed sample testing of the tailings to be impounded can also provide values for the necessary design parameters. Typical void ratios and possible shear strength of emplaced tailings can be approximated in a simple laboratory model, such as that shown in figure 5, in which the tailings are

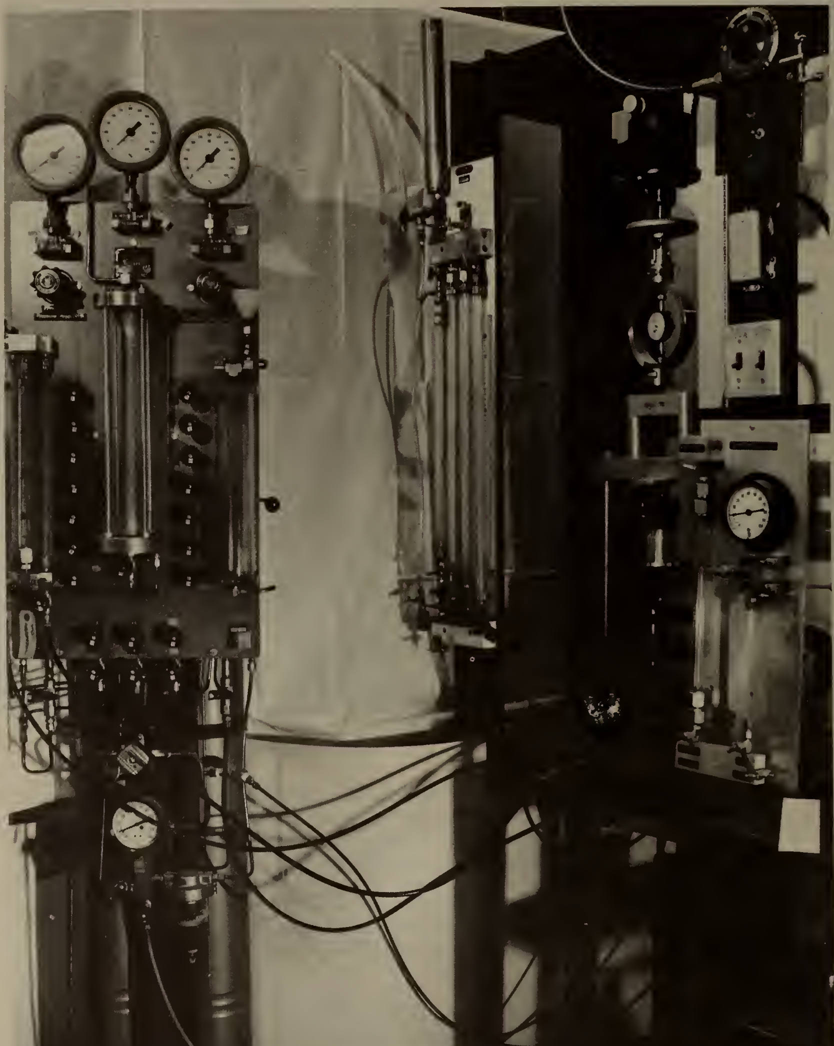


FIGURE 2. - Triaxial Test Apparatus.

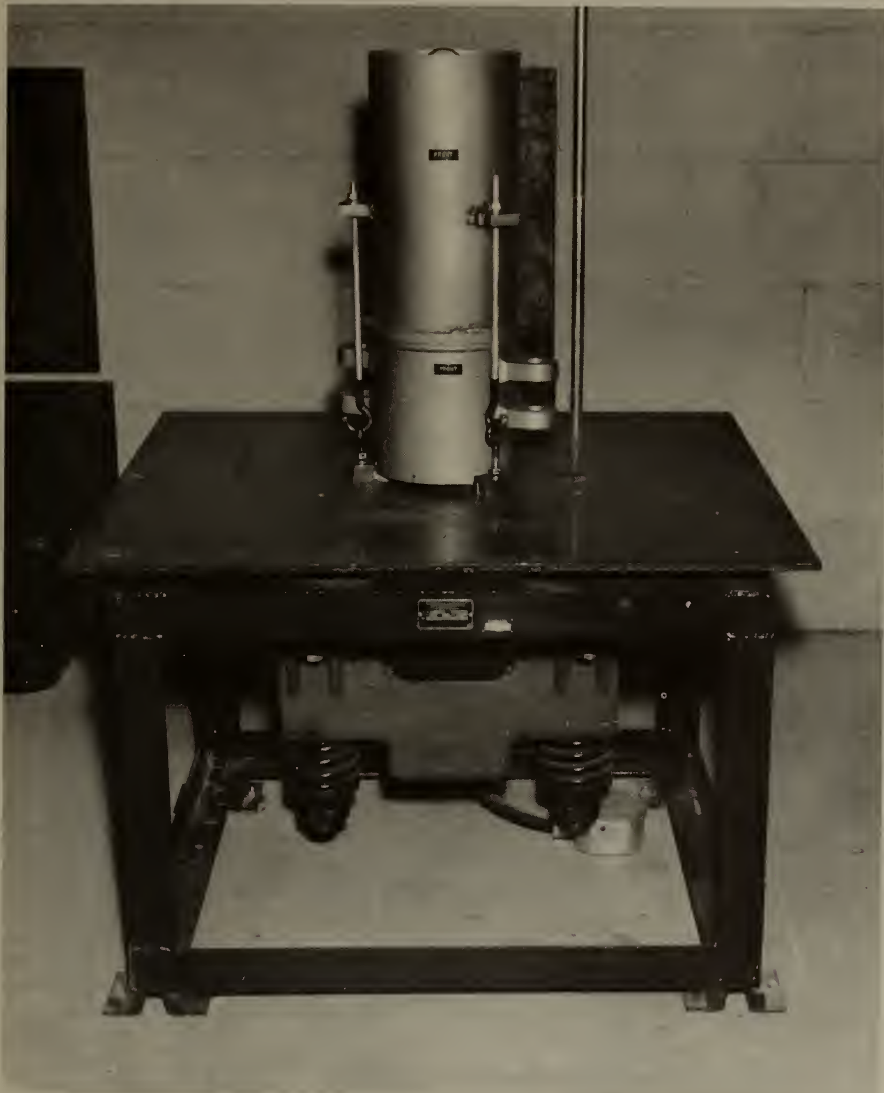


FIGURE 3. - Relative Density Test Apparatus.

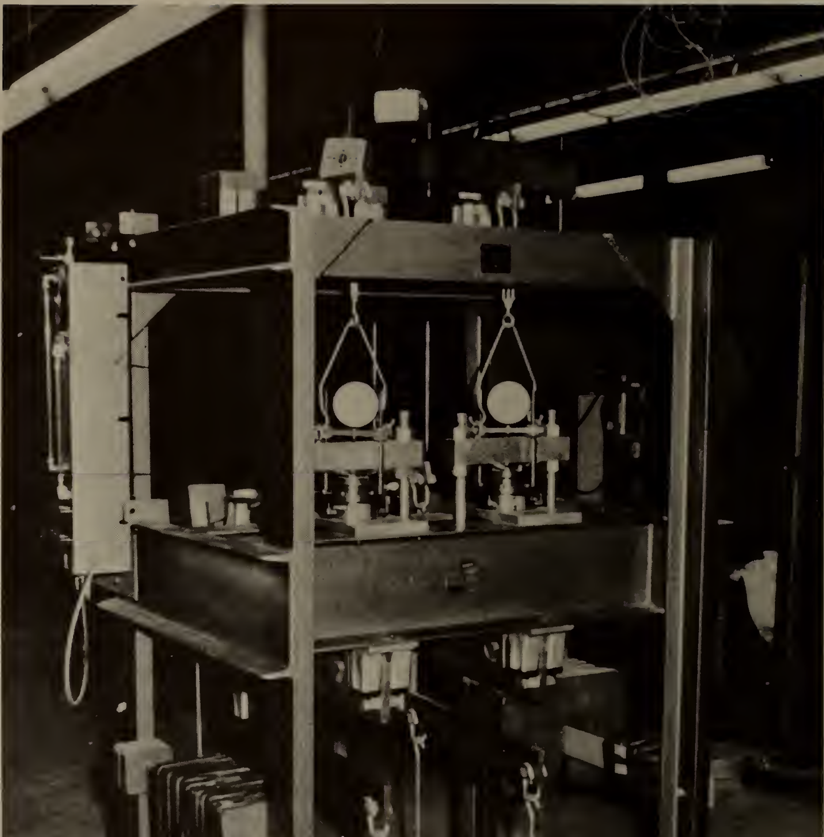


FIGURE 4. - Consolidation Machine.

FIGURE 5. - Laboratory Model of Tailing Pond.

poured at the slurry density expected to be used in the proposed pond. Samples are extracted and subjected to standard tests. Consolidation tests performed on the extracted samples can approximate what will happen to the soil as the height of the pond increases, thus changing the three most critical design parameters, density, shear strength, and permeability. Figure 6 is the shear diagram developed in our laboratory for one particular soil. As indicated by the shear diagram, two phi angles (ϕ) are developed from the direct shear test. It is probably more realistic to use the ultimate phi angle for stability calculations, discounting some intergranular friction. Reasonably good stability predictions can be obtained by using these phi values in a slope stability analysis. Figure 7 shows the effect of density and grain structure on the coefficient of permeability.

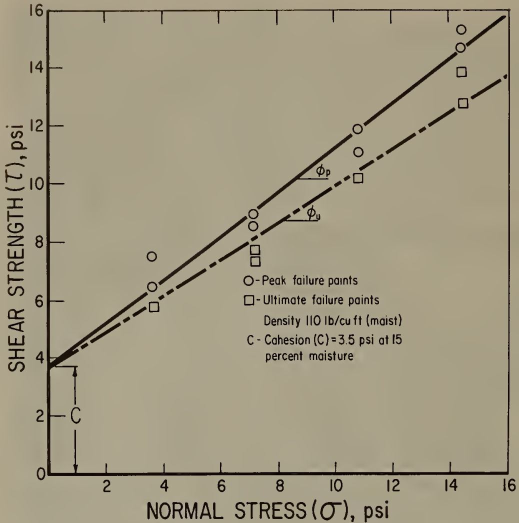


FIGURE 6. - Direct Shear Diagram.

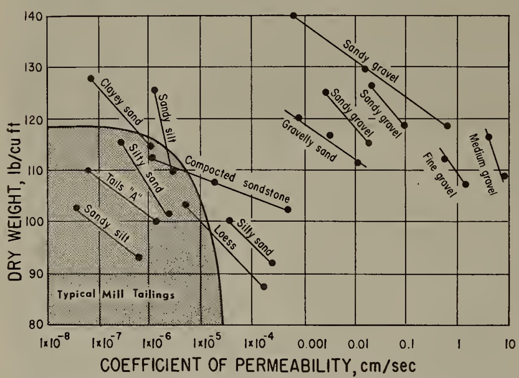


FIGURE 7. - Density as Related to Permeability. (From Cedergren (2).)

BASIC DESIGN METHODS

Two basic techniques for constructing tailings dams will be covered in this report: (1) the use of mill tailings themselves as the construction medium and (2) the use of borrow material to construct the retaining structure and impound the tailings.

There are three basic construction methods: (1) the upstream method, (2) the downstream method, and (3) dams from borrow material. Each of these methods has its function depending on locality, climate, type of operation, etc.

Upstream Method--Design Techniques

One of the biggest problems observed on visitations throughout the United States is that the initial starter dike, which is typically used in upstream disposal systems, is frequently constructed of clay, on the assumption that this is best for the pond. A clay dike, however, which has a water-retaining ability and critical location, will hold water that promotes instability by reducing the cohesive strength and raising the phreatic line (2, 6).

Considerable effort should be made to see that the starter dike is built on a strong base having a scarified surface free of all organic matter. The dike can be constructed of coarse rock, gravel with sand mixture, or any pervious material as long as the upstream side has a gradation into sand to prevent the piping of tailings through the rock. This starter dike, which ultimately becomes the toe of an immense structure, should be as structurally sound as the footing under a building.

The most common upstream method, and probably the cheapest and best, is to place the main line around the periphery of the dikes. The line should discharge into the pond every 10 to 50 feet, depending on the size of the installation. Bleed lines, which range in size from 2 to 6 inches, can be used to build up the dike to heights of 20 to 30 feet in 8- to 15-foot increments before the main line must be moved (figs. 8-9). If the density of the discharge is low enough and there is a relatively large size differential between the coarse and fine fraction, a beach of considerable size is the result. Cyclones, if necessary, serve a useful purpose because they (1) keep the coarse material, which is excellent for berm building, at the outside and (2) can discharge the slime fraction far into the pond if desired (fig. 10). Figure 11 shows effective and ineffective relationships of slime deposit to the berm. In large ponds having a wide beach (200 to 300 feet), as the upper panel shows, the dams can be built to a much greater height, with even a 1-1/2 to 1 or a 2 to 1 slope, before any previously deposited slimes lie directly below the newly placed berm.

Probably the most unsafe practice, on the other hand, is to discharge the tailings so that the slimes and water lie against the dike. With this method there will be slimes from bottom to top, as the lower panel shows, held by a relatively thin shell of berm, generally of borrow material. This slime material has a high void ratio, retains vast amounts of water, and has a low bulk density, low phi angle, and consequently lower shear strength than does a sandy material. The phreatic surface (upper limit of water saturation) is high in the dike on both the upstream and downstream sides. Consolidation of the material takes place slowly because of the necessarily slow buildup in the dam's height. Because the horizontal and vertical permeability is very low, water is squeezed out slowly and it takes longer for the slime material to attain any shear strength. The material for some distance back from the berm and for a considerable depth is saturated, has no cohesion and no shear strength, and is held in place by the berm only. The berm itself becomes saturated, reducing the safety factor still further. In general, it is good to pool the water against the uphill side of the area as far away from the periphery of the dike as possible.

When building the berm, whether by dozer or dragline, an effort should be made to obtain compaction either by dynamically dropping the sand load or by running over it a few times with a dozer. As described very well by Hough (3), compaction of a soil produces a tremendous increase in shear strength. The berm should have both good compaction and high permeability in order to transmit a free flow of water to the outside, while being sufficiently compact that, if it is saturated, a sudden load or seismic shock will not cause liquefaction. When liquefaction does occur, the berm loses all shear strength, the water takes the load, and failure is instantaneous. The beneficial effect on stability by compaction of the berm outweighs the decreased permeability produced by the compaction.

FIGURE 8. - Distribution Pipes off Main Line Around Tailing Dam.

FIGURE 9. - Berm Built With Dragline From Beach Sand.

FIGURE 10. - Cyclones on Dam.

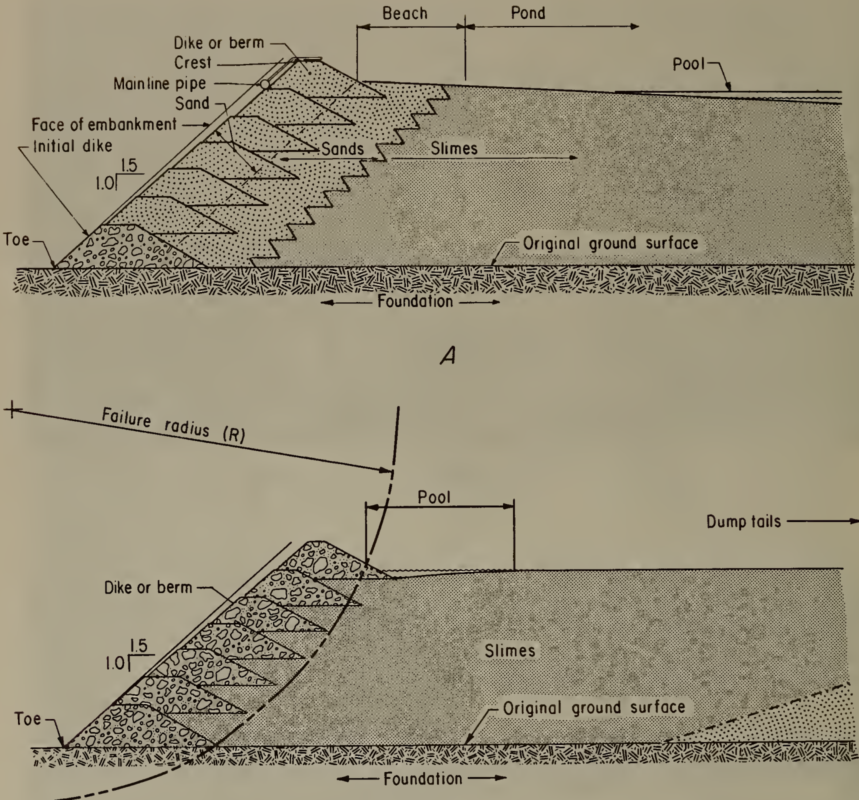


FIGURE 11. - Slime Deposit Relative to Berm. *A*, High dam showing slimes directly below berm at great height; *B*, slimes against berm of borrow material.

Downstream Method

Some foreign mines use a type of berm building that is the reverse of common practice in this country. The coarse material discharged from cyclones around the periphery of the dike is deposited on the outside of the toe; the slimes are deposited on the inside (fig. 12), producing a very pervious, triangular dam, which is very stable and safe but requires much more labor for moving and tending the cyclones. Because the area of the dam increases as it

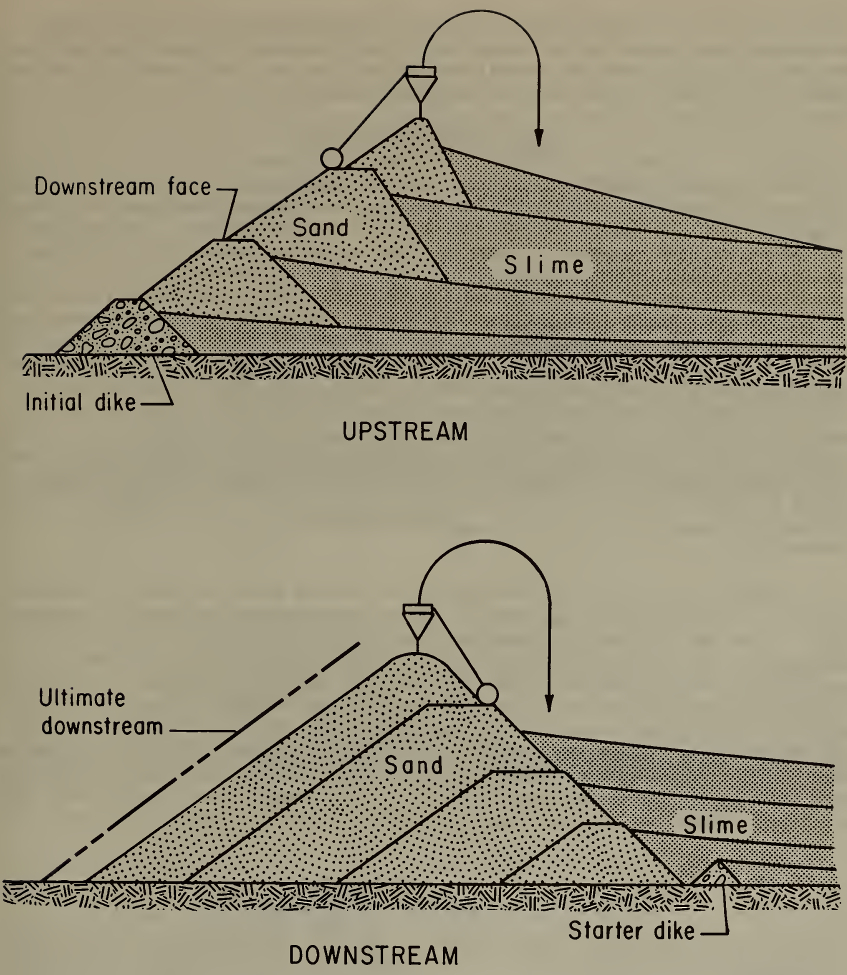


FIGURE 12. - Comparison of Downstream Versus Upstream Building Techniques.

gets higher, more and more sand is required per foot of elevation rise in the dam, as can be seen by examining figure 12. This method can be safely used in building very high dams because of the bulk and density of the mass of sand; height is limited only by the volume of available sand. The downstream slope must be calculated for each operation and is governed by the shear strength,

etc. Only mines not using their tailings for underground fill would have enough sand available for building dams in this manner. Even then, however, the additional cost is not normally warranted, since a very good dam can be built by previously described conventional methods.

Dams of Borrow Material

Tailings dams that do not use peripheral discharge, but simply dump the sand at the high side of the tailing area or are impounding slimes only, would normally be the only ones with berms built of borrow material. Occasionally the operators might prefer to make the berm of borrow material even though sand is available. Borrow material is very often 85 percent sand and 15 percent clay, or some mixture of gravel, sand, and clay. A decrease in the clay content from 15 to 10 percent can make a big difference in the permeability (k) of the embankment. As Cedergren has pointed out (2), grain shape, size, and gradation are extremely critical in determining permeability. In localities where the dams are built of from 85 to 90 percent sand and 10 to 15 percent clay, the phreatic waterline assumes a slope of 5 to 1. These dams are designed so that the line will intersect the base well within the toe of the dam (fig. 13). The location of the phreatic line is critical to slope stability. A small addition of clay can change the slope of the phreatic line to a figure as great as 6 or 7 to 1, creating instability. If the pond is filled slowly, the phreatic line in the dam can be carefully monitored with piezometers.

A high clay content in sand and gravel borrow material placed unzoned results in a homogeneous dam that is quite impervious when tightly compacted (10). Although a common practice in some places, this is not desirable because the waterline will be high in the dike even with a wide deposit of sand (beach) along the inside of the dam. The phreatic line will intersect the berm at the same point and emerge high on the downstream face. The outside of the dike will eventually slough and fail. Because the berm is more impervious than the material it is containing, the berm will govern the water level. A loosely compacted berm will fail very soon; a very highly compacted berm will take somewhat longer to fail. Local sloughing and piping will show on the outside of a clay berm and is a warning that failure is imminent.

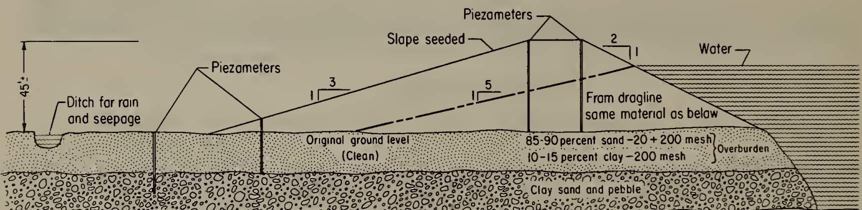


FIGURE 13. - Typical Slimes Dam.

Stability can only be achieved by proper zoning. Borrow material and/or classified mill tailings can, if properly placed, produce the desired dike section as illustrated in figure 14. Figure 14A illustrates a homogeneous mix alone, which does not control the seepage water without the filter and coarse zone downstream. Figure 14B illustrates the very unstable condition provoked by improper alinement of the zone section; that is, the downstream zone permeability (k_1) is more impervious than those upstream (k_2 and k_3). Figure 14C shows that the same material as that used in figure 14B, when properly placed, can provide excellent seepage control and consequently better stability.

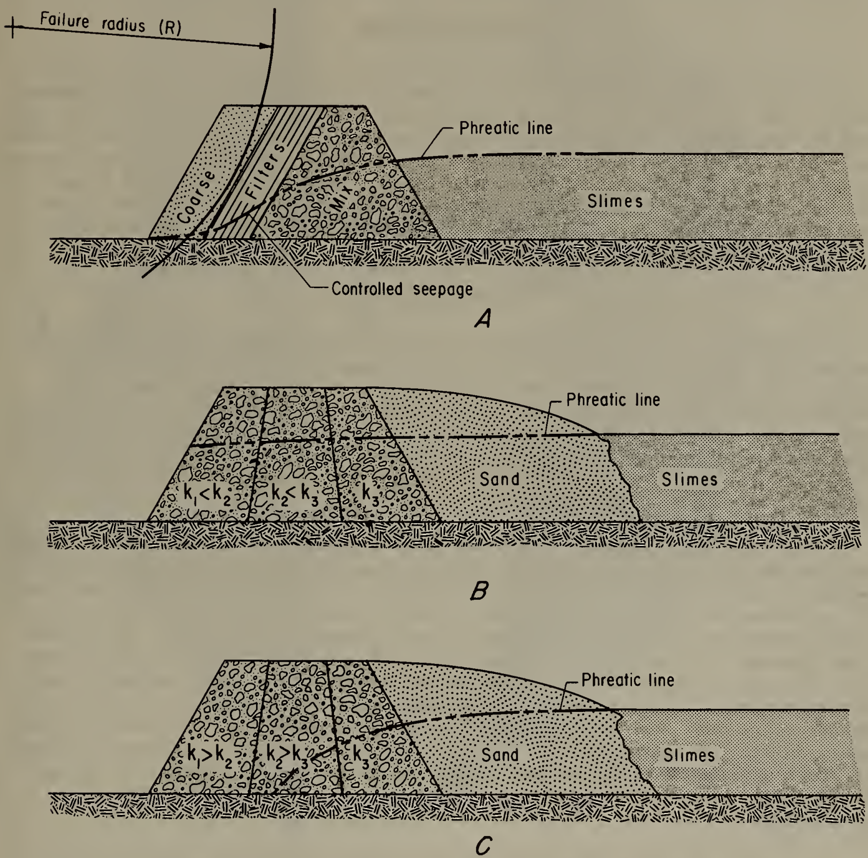


FIGURE 14. - Dam Stability Correlated With Zoning.

Water-Dam Construction

Cyanidation mills and some iron ore plants which have contaminants that cannot be released into streams without treatment generally use the water-dam type construction. Some phosphate plants also use this type of dam to impound slimes. Water-dam construction is very costly and does not permit the free drainage of slimes for ultimate disposition. The design of these dams, which is well covered in the literature (7), corresponds to the purpose it is to serve and to the terrain and climatic conditions of the geographic area.

Rock-Fill Dams

Rock-fill dam construction is a unique way of disposing of coarse mine and/or plant waste materials in the process of constructing tailings-disposal ponds (fig. 15). Such a construction method provides excellent stability and can provide a built-in spillway through the "soil weir" to guard against over-topping. The method is best used when the tailings structure must be built in a stream or river channel and provides for the passage of watershed flows through the pond. Ultimate water movement and the dewatering of the slimes can be accomplished by adding adequate drainage, for example, sand drains, when the structure is to be abandoned.

FREE-WATER CONTROL

Free-water control is common to all three previously discussed building methods and is one of the most critical features in the disposal system. Return water can be removed from the tailing pond (1) through towers and decant lines, (2) by barge pumps on the surface of the pond, and (3) through siphons off the top of the pond to permanent pump installations. With any of these systems there must be absolute control of the water in the dam, both to regulate the return water needed and to keep the water as far back from the perimeter of the dike as possible.

The tower and decant line system is very good where a firm base is available on which to build. In large installations they must be built to withstand the load without sinking into the base or being crushed. If practicable, it is advisable to build the lines on bedrock using heavily reinforced concrete, with water decant holes every 2 to 6 inches of elevation. The decant line through the dam should have several seep rings to prevent piping along the line and ultimate failure. The towers also must be constructed of reinforced concrete, strong enough to withstand wind as well as other loads. The decant holes must have positive and foolproof cutoff stops, for once they are under 50 feet of slime they are expensive if not impossible to repair. Figure 16 shows a large decant line and tower. In large installations, the decant lines should be built large enough that they can be entered for visual inspection.

In the smaller installations of relatively low height and short life, a solid steel pipe or reinforced concrete pipe on a firm base with several seep rings is adequate. If the pond is built against a hill, the decant line can be run upslope and pipe can be added to regulate pond elevation as the dam height increases.

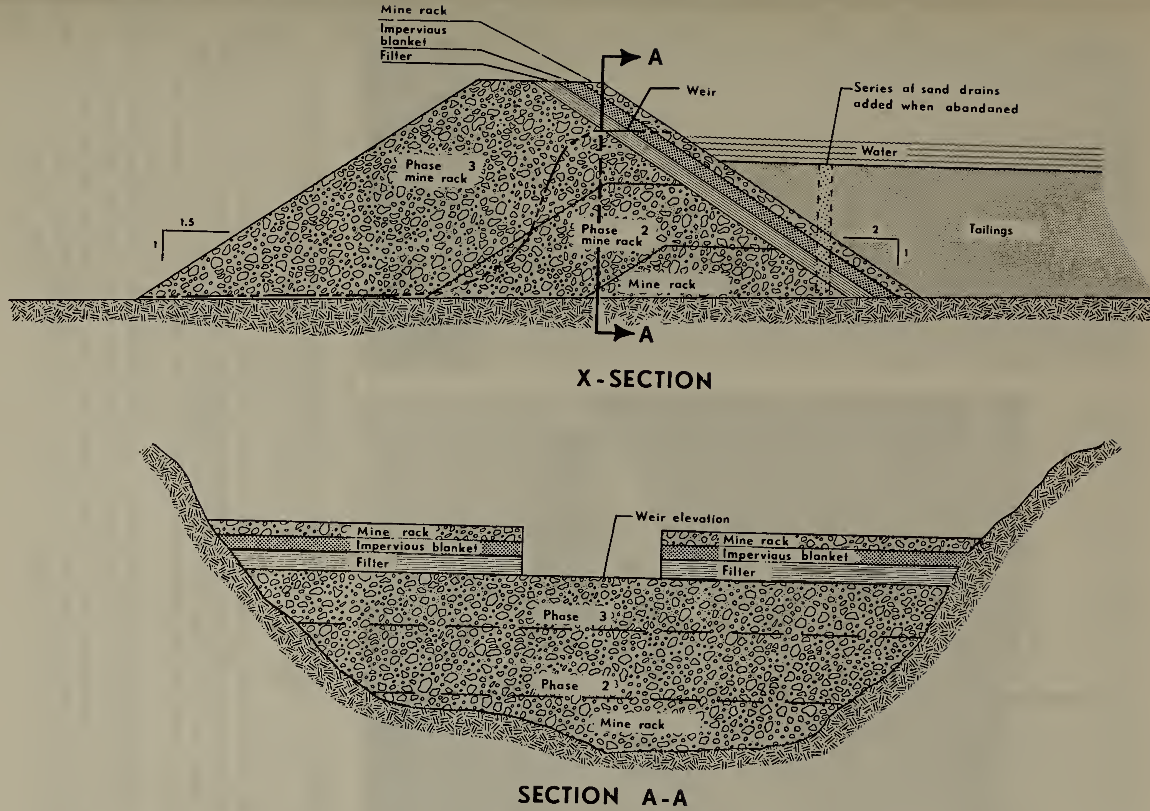


FIGURE 15. - Rock Fill Dam.

FIGURE 16. - Two Decant Systems. Left, decant line with drains at 6-inch elevation; right, decant tower with drains at 4-1/2-inch elevation.

The advantages of the decant system include (1) the possibility of planning and construction well in advance of actual tailing deposition, (2) permanent pump installation (that is, no relocation is required), (3) drainage through the area after abandonment, and (4) the simplicity of operation.

The disadvantages of the decant system include (1) possible deterioration of the dam by piping, (2) difficulties of adding on to the top of decant towers, (3) increased cost of pumping water from the bottom of the pond as compared with pumping from the top, and (4) possibilities of failures or leaks occurring along tower or line.

Barge pumps and siphons are used on many dams. Besides eliminating costs for towers and lines, these methods are more advantageous than decant towers in that there are no pipes of any kind which might fail within the dam, and there is less lift of water for return to the mill.

Some of the difficulties involved with barge pipes and siphons follow:

1. Raising the pumps as pond level rises, although not difficult, requires care.

2. Power outage leaves no place for water to go and could cause overtopping of the dam.

3. Freezing weather is a nuisance. (Compressed air or circulating water must be used to keep ice from the barge.)

4. There is no way to take care of surface drainage after abandonment.

5. The siphon can lose its prime with subsequent rise of water level.

6. In a siphon system, the water must be against the dike unless other arrangements are made.

SLOPE STABILITY

Slope stability analysis, until recent years, has been a long and tedious calculation. Now, however, computer programs are used to calculate and select the minimum failure circle. There have been numerous programs written for the Fellenius method, the original method of slices, and the Bishop method. The Fellenius method develops a conservative estimate since it completely neglects the side forces on the individual element slices; the Bishop method is the more accurate. A study of all of these programs has resulted in the selection of the modified Bishop program, originally written at M.I.T. and slightly modified at the Bureau of Reclamation, to include both the Bishop and the Fellenius factors of safety (1). The Bureau agrees with R. V. Whitman and W. A. Bailey that this is the best program available today (11).

The factor of safety is defined as the moments about the center 0 for the circular failure are ABCD, as shown in figure 17, and is described by the equation

$$F = \Sigma \frac{(\overline{C}\ b \sec \delta + \overline{N} \tan \phi)}{\Sigma\ W \sin \delta}, \qquad (1)$$

where W = weight of soil and water, lb,
$\overline{C}$ = cohesion for soil, lb/sq ft,
b = width of slice,
δ = element angle,
$\overline{N}$ = effective normal force,
ϕ = friction angle,
and F = safety factor.

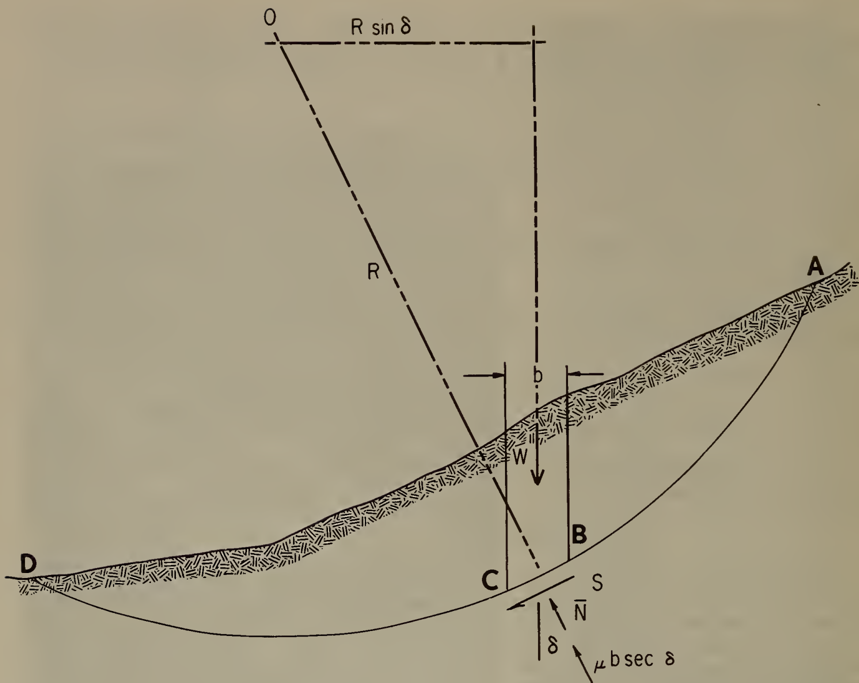


FIGURE 17. - Circular Failure Arc.

The denominator of the equation for F is an exact expression for the moment of the weight of the soil in the failure mass. (The radius R cancels since it occurs in both the numerator and denominator.) The numerator is the moment of the shear stress about 0 along the failure surface.

$\bar{N}$ is determined for the simplified Bishop method by the sum of forces in a vertical direction, according to the equation

$$\bar{N} = \frac{W - b \sec \delta \left(\mu \cos \delta + \frac{\bar{C}}{F} \sin \delta\right)}{\cos \delta + \frac{\tan \phi \sin \delta}{F}}, \tag{2}$$

where μ = pore pressure, lb/sq ft.

Thus

$$F = \frac{\Sigma\left[\bar{C}\, b + (W - \mu b) \tan \phi\right] \dfrac{\sec \delta}{1 + \dfrac{\tan \phi \tan \delta}{F}}}{\Sigma W \sin \delta}. \tag{3}$$

Since F appears on both sides of the equation it must be solved by successive approximations. This is the equation for which the complete program was written.

The computer will systematically search through the numerous failure circles as outlined in the guidelines of the program. It will select a minimum failure circle (the plane along which failure will normally occur) while also computing the individual circles so that the effects of the geometry, etc., can be studied in each case. At the end of the program the computer will list the minimum of all the circles selected for that particular embankment and conditions.

The simplest way to illustrate the mechanics of the computer program is to present an example. Figure 18 shows the soil properties and the location of minimum failure circles for two different conditions that were analyzed. Case 1 assumes a high phreatic line, and case 2 assumes the water table at ground level. Although the geometry and soil structures are identical for both analyses, the difference in the location of the phreatic line does alter some of the soil properties, as shown in figure 18. By comparing the computed minimum safety factors (1.14 versus 2.67) one can see that the location of the phreatic line is very critical for determining stability. A factor of safety of less than 1 is a failure situation, above 1 is a stable situation, and 1.5 is normally considered a safe design value, particularly if the soils are somewhat coarse and not likely to be subjected to seismic activity.

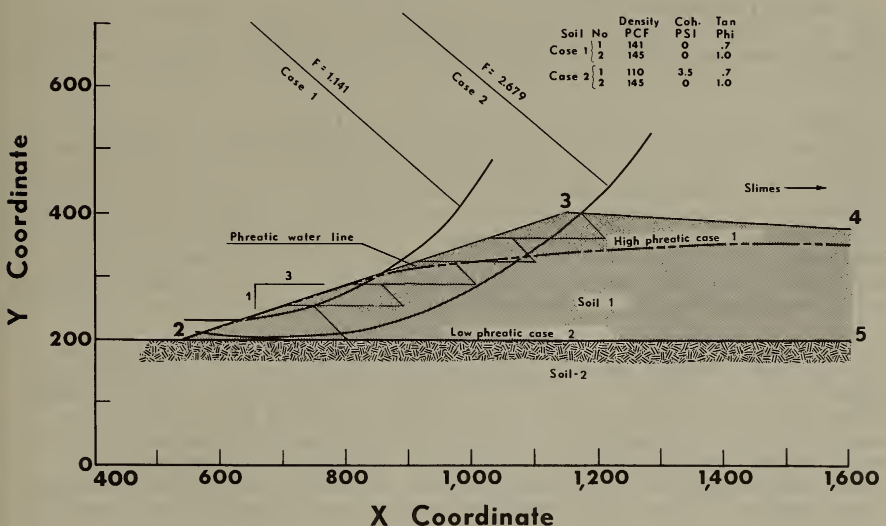


FIGURE 18. - Sample of Computer Analysis.

Complete computer listings of input and output for cases 1 and 2 have been included as appendixes for those who would like to study the computer searching and analyzing procedures in more detail. All of the failure circles tried are listed, and the factor of safety is computed for both the Fellenius and Bishop methods.

Should the embankment conditions indicate other than a circular arc failure, a second computer program using the Morgenstern and Price procedure can be used (5). With this program any desired geometric failure plane can be described and the factor of safety attained in a few minutes of computer time. Unlike the Bishop program, it does not search for the minimum safety factor but produces only the input failure plane. Since the development of computers, the most difficult part of the slope stability analysis is providing correct input data, a point that cannot be overstressed.

In most cases it is extremely difficult, if not impossible, to obtain soil samples that are truly representative of the zone being studied. Consequently, the soil properties developed from these samples must be interpreted and applied with great care. Assuming that input values developed are representative of the actual case being studied, the computer factors of safety are only general guidelines and are meaningful only if used in conjunction with all of the other design considerations.

FURTHER DESIGN CONSIDERATIONS

The engineer must anticipate and design for the worst possible condition, that is, ultimate height, maximum phreatic line, saturated soils, and seismic activity, when determining values to place in the computer program. Only then will the safety factor be meaningful.

Grain size distribution, the area of the tailing pond, and the rate of discharge have much to do with the stability of the embankment. A finer grind in the mill combined with the coarse fraction being taken out for use as underground fill has made dike building more difficult. Combine these factors with the small pond area compared with the tons of waste per day and the situation becomes worse. The tailings used underground at some properties do reduce the total that must be impounded on the surface by 40 percent or more, but they also remove the coarse sand, the best material for building the dike, and the coarse sand beach which provides added safety in front of the dike.

An example of rapid building is a situation in which a 500-ton-per-day operation has 300 tons per day impounded in a 5-acre site with a pond rise of 1 foot in 33 days or even a 10-acre site with a 1-foot rise in 66 days. Such situations could cause a rapid increase of pore pressure because the water does not have time to percolate through the fine material, especially if the dam is impervious and there is no peripheral discharge, leaving water and slimes against the dike. Even with the best of conditions, too rapid building is not good, and every effort should be made to keep the annual rise compatible with the seepage ability of the soil.

Piezometers installed in proper places in the embankment will allow monitoring of the pore-water pressure in the dam which can be related directly to the safety factor as shown in figure 19, a typical graph showing the variance of safety factor with phreatic water height in the dam. Through engineering soils mechanics, this type of chart can be developed for any dam and used by the operators as a monitoring device to predict the safety of the embankments. The phreatic surface is related to the rate that material is placed around the periphery of the dike.

If disposal areas must be small, additional areas must be provided when monitoring indicates the approach of an unstable situation. This will allow the area to decant and drain, consolidate, and lower the waterline. By alternating between two or three small areas, each one becomes more useful and will have a greater ultimate capacity. Operations in areas having extreme weather that prohibits berm building in the winter must build sufficient berm during good weather to allow dumping in large ponds during winter months.

In a seismic area safety factors cannot be accepted at face value because of the possibilities of liquefaction from either earthquake, sonic blasts, or sudden load owing to the inherent moisture and density of the material. Soils in the 80- to 280-mesh sizes, saturated, and above the critical void ratio, are very sensitive to liquefaction. Soils finer than that would be too sluggish in their reaction to shock because of low permeability, and those coarser would dissipate the water fast enough to make failure from shock unlikely.

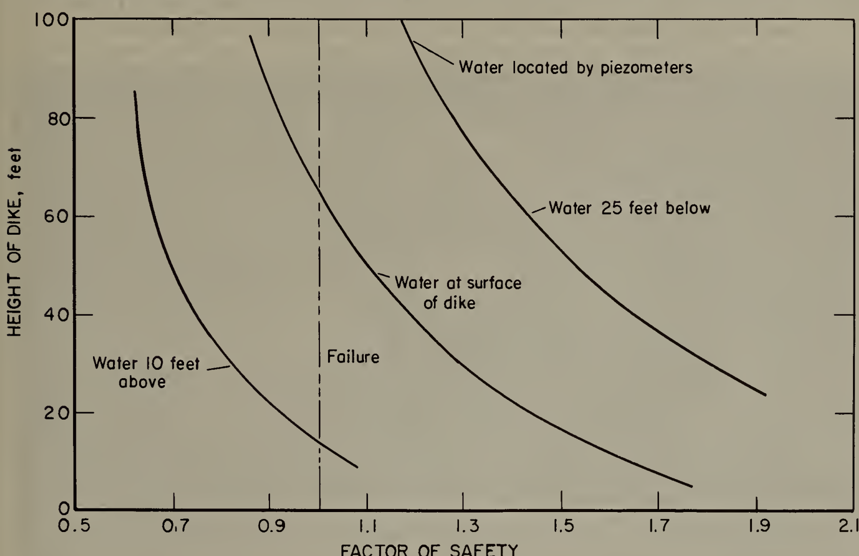


FIGURE 19. - Factor of Safety From Phreatic Water Height in Dam.

All soil testing requires stringent testing conditions and experienced personnel. Since Coulomb's theory and stability equations are approximations, these samples have to be studied thoroughly by experienced soils engineers to insure that true values are obtained for any stability analysis (9). Once these values have been interpreted, it is simple to predict the stability with today's computer usage. Ultimate height, slope, and water movement can only be determined by soil engineering analyses. Before any major construction of this type, these analyses should be made either by the operating firm or by a consulting agency; the cost is only a few percent of the total investment.

SEEPAGE WATER CONTROL

The movement (loss) of water in a tailings pond varies considerably between the start of filling and eventual abandonment. Initially, a pervious base has stability advantages because of water movement through the bottom, but as the height increases and the slimes accumulate over large areas, consolidation reduces the permeability of the base. As the height of the dam increases, the effect of the original base becomes negligible, and the tailings themselves have an overriding effect on the downward movement of water. A tailings dam that starts with a permeable gravel base will ultimately develop an almost impervious base owing to the fine tailings percolating downward and the underlying tailings constantly being consolidated (fig. 20). Note that if the sands can be placed near the interior toe of the dike the pervious base remains effective and will function like a longitudinal drain, while the lower phreatic line may be used for stability analysis. If one cannot assure this, the permeability (k) of the entire base approaches zero and the upper line must be used for stability analysis. As this structure increases in height, its condition could change from very stable to very unstable unless the outside is kept free-draining. Frozen conditions can also impair stability (fig. 21).

Instrumentation for measuring pore-water pressure and horizontal and vertical movement in embankments is essential in any tailings structure. The location of the phreatic waterline is most accurate when obtained with piezometers (fig. 22) in the pond and berm itself. Checking the water level in a dam in an uncased hole can produce erroneous results. Excess pore-water pressure will not be observed, as the water can dissipate into a coarse sand layer and thus not rise as high as it would in a cased hole or piezometer.

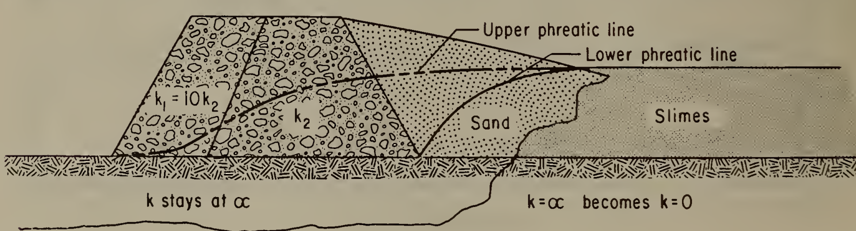


FIGURE 20. - Change of Base Permeability With Time and Material.

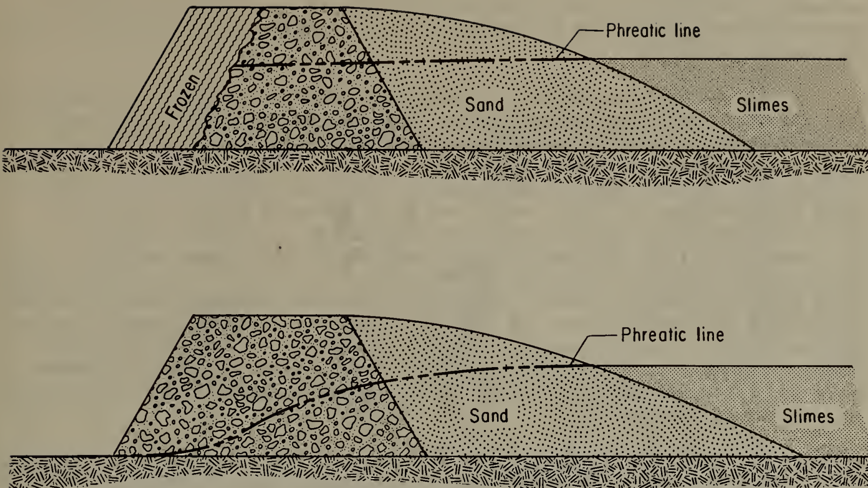


FIGURE 21. - Location of Phreatic Line for Frozen Versus Unfrozen Face.

FIGURE 22. - Porous-Tube Piezometer and Electric Tool for Measuring Water Depth.

Another important instrument, a slope indicator or crossarm settlement device (7), is used for the internal measurement of vertical and horizontal movement. Knowledge of the location and extent of movement is essential to predicting the behavior of the structure and to taking any corrective measures that may be required.

If the dam is to be built in an area for which no in-place information is available, the phreatic surface can be estimated by the solutions of the La Place equations using flow-net construction or the finite element method. Computer programs have been written for the finite element method to predict the location of this phreatic surface line (8). The program used in this study was developed by R. L. Taylor and C. B. Brown of the University of California (Berkeley Campus) and later modified by J. T. Christian and B. J. Watt of M.I.T. This program utilizes the finite element method to determine pressures and flows as governed by Darcy's law. Correct hydrostatic head, geometry, and horizontal and vertical permeability according to the inclination and layering are the only input data required for predicting the phreatic surface. Using these values, the computer will search through the numerous phreatic surface lines and adjust pressures at the finite element nodes so that equal potential lines and the phreatic surface can be obtained in a matter of minutes.

Typical phreatic lines that can be developed are illustrated in figures 23-25. Note the effect of embankment stratification and the corresponding horizontal permeability (k_h) and vertical permeability (k_v) on the location of the phreatic line and on the required width of longitudinal drain (fig. 23), the relationship between downstream shell permeability relative to foundation permeability and the saturation level in the shell (fig. 24), and the effects of zoning and stratification on the location of the saturation line (fig. 25).

RECLAMATION

Reclamation of tailings ponds as practiced in the United States varies with each operation and climatic area, though some problems are basic. In several areas the land is returned to as near the original condition as possible, or even improved upon. Elsewhere the goal is limited to the prevention of air and water pollution. Making reclamation an inherent factor in the design of tailings dams may reduce the ultimate cost which must be borne by the consumer. However, reclamation is a study in itself, and a detailed treatment is not attempted in this report.

Considerable research is concerned with promoting the growth of trees, grass, and native foliage in an attempt to beautify abandoned tailings areas. Some tailings are so toxic that it may be years before plant material will begin to grow. In such cases it may be necessary to place a few inches of soil before planting grass or to place an inch or two of gravel to allay the dust while waiting for oxidation and leaching to be completed sufficiently for native growth to take over. The most economical precautionary dust control measure observed to date is the placing of a 3- to 6-inch layer of coarse material, either gravel or mill slag, on top of the pond. The possibility of placing this material pneumatically is currently being investigated. To date it has not been feasible to prevent dust in an active pond.

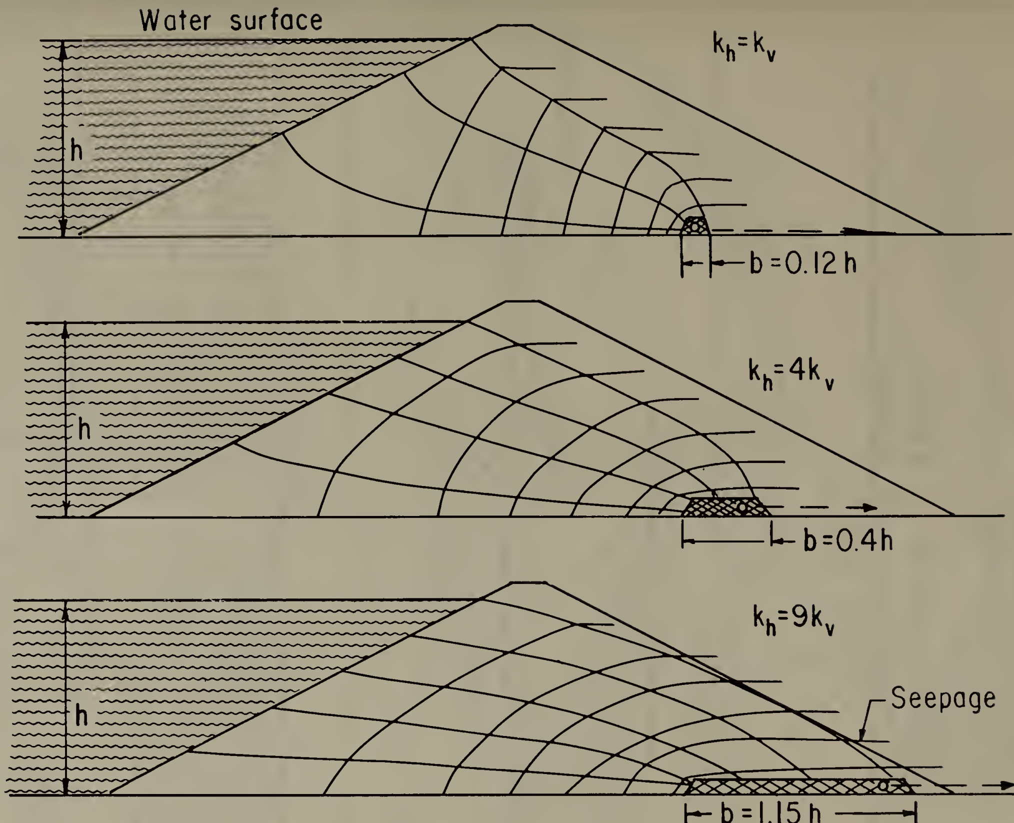


FIGURE 23. - Effect of Embankment Stratification on Required Width of Longitudinal Drains in Homogeneous Dams and Levees. (From Cedergren (2).)

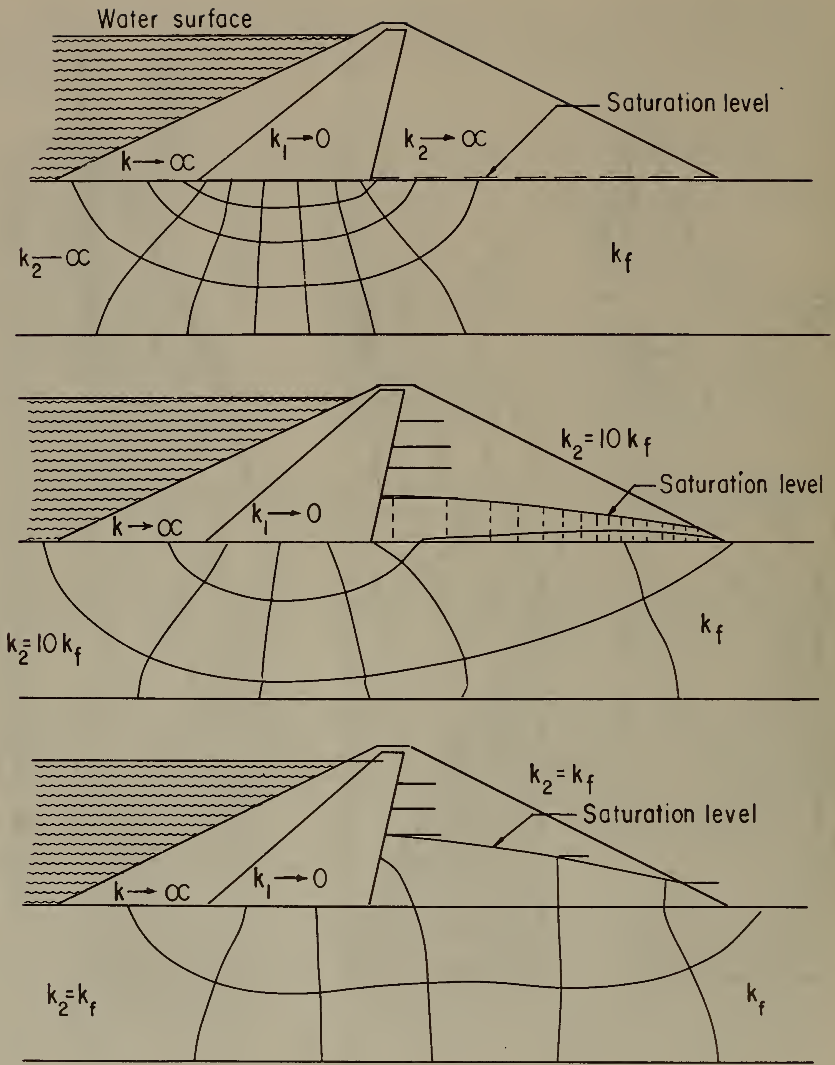


FIGURE 24. - Zoned Dam Study. (From Cedergren (2).)

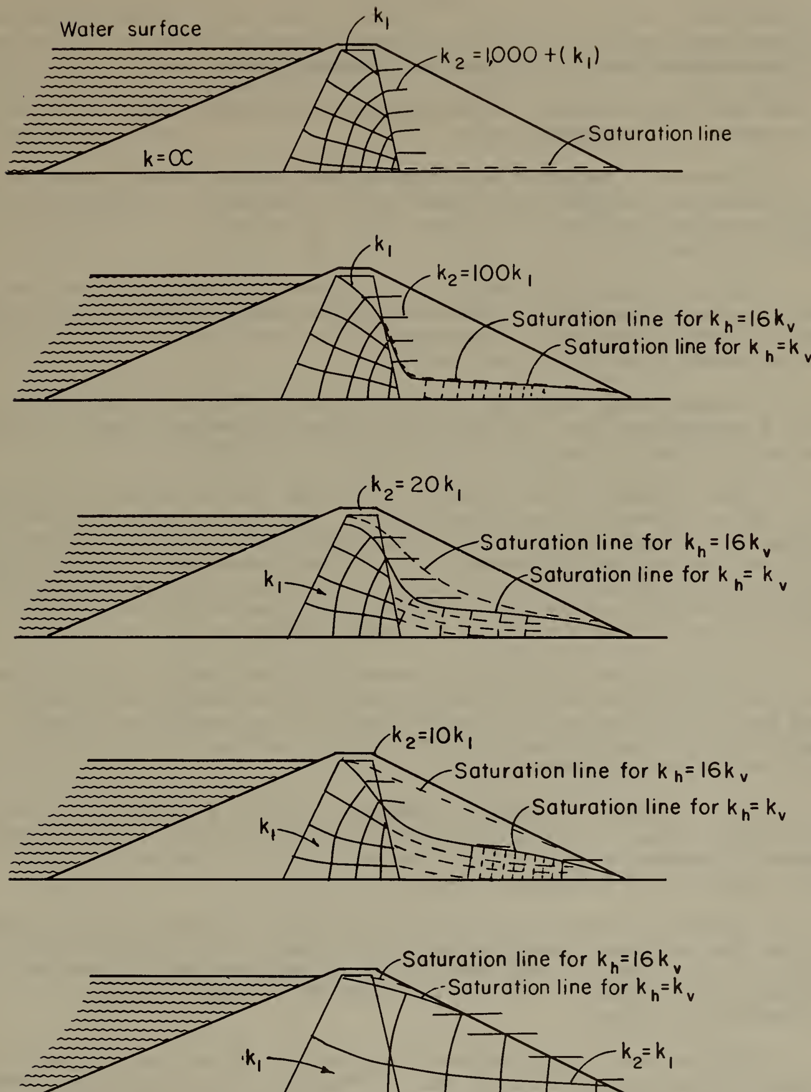


FIGURE 25. - Flow Nets for $k_h = k_v$. (From Cedergren (2).)

CONCLUSIONS

This survey has resulted in the following recommendations concerning the construction of effective, long-lasting tailings disposal dams:

1. Test the foundation soil to determine the subsoil design parameters and to remove any incompetent soils.

2. Construct a foolproof decant system that permits visual inspection and, if possible, provides for ultimate surface drainage. The decant circuit should be designed so that if one decant fails an alternate is available to prevent topping, etc.

3. Never construct homogeneous dams. Zoned-type construction must be used to control seepage water and consequently increase stability. Since compaction of borrow material in a homogeneous dike is of little value, the money expended should be directed toward zoning.

4. Starter dikes should not be built of clay. When the outer shell consists of cohesionless soil (as used with the upstream method), some consideration must be given to compaction to avoid possible liquefaction.

5. Most critical in the design of a tailings disposal system is the complete control of both free and seepage water. When impounding low-permeability tailings the disposal area should be large enough that the annual rise will be only a few feet or, as an alternative, two or more areas should be available so that proper drainage can be attained. The tailings should be distributed around the periphery of the dike through bleeder pipes off the main line, and the pool should be kept as far from the dike as practical.

6. Dams and ponds should be instrumented and monitored at definite time intervals to check the water movements. The factor of safety can be determined from charts constructed for this purpose. Ponds should be checked at regular intervals, and adequate records and maps showing time, tonnage, and elevations should be maintained.

7. Keep the soil permeability constantly decreasing upstream. Natural consolidation owing to overlying tails will automatically cause the vertical decrease of downward permeability. These permeability arrangements greatly affect stability and seepage patterns.

8. Because a pervious gravel base will be made ineffective by deposition of slimes and subsequent consolidation as the height of the tailings deposit increases, the minimal estimate must be used in designing the ultimate phreatic line. The higher the dike and the finer the material, the greater are the chances for failure.

A structure that will be stable during the life of the property must be designed for any tailings disposal dam. Furthermore, the system should render the company free of all liability upon abandonment and/or provide for reclamation of the area. Not only is the engineering cost small, but it is also an

essential investment since only a few expensive and basically ineffective emergency measures can be taken to avert a developing failure. The development of the associative slope stability and waterflow computer programs have made it possible to design for ultimate conditions of height, slope, etc. The soils engineering and testing methods that have been well developed for mill tailings disposal systems should be applied, as well as geologic and hydrologic studies.

REFERENCES

1. Bailey, William A. Stability Analysis by Limiting Equilibrium. Civil Eng. Thesis, Massachusetts Institute of Technology, 1966, 68 pp.

2. Cedergren, Harry R. Seepage, Drainage, and Flow Nets. John Wiley & Sons, Inc., New York, 1967, 467 pp.

3. Hough, B. K. Basic Soils Engineering. Ronald Press Co., New York, 1957, pp. 97-134.

4. Karol, R. H. Soils and Soil Engineering. Prentice-Hall Inc., Englewood Cliffs, N. J., 1960, pp. 14-25.

5. Morgenstern, N. R., and V. E. Price. The Analysis of the Stability of General Slip Surface. Geotechnique, v. 15, 1965, pp. 79-93.

6. Parcher, James, and Raymond Means. Soil Mechanics and Foundations. Charles E. Merrill Publishing Co., Columbus, Ohio, 1968, 543 pp.

7. Sherard, J. L., R. J. Woodward, S. F. Gizienski, and W. A. Clevenger. Earth and Rock Fill Dams. John Wiley & Sons, Inc., New York, 1963, 671 pp.

8. Taylor, Robert L., and C. B. Brown. Darcy's Flow Solutions With a Free Surface. Am. Soc. Civil Eng., J. Hydraulics Div., v. 93, No. HY2, March 1967, pp. 25-33.

9. Terzaghi, Karl. Theoretical Soil Mechanics. John Wiley & Sons, Inc., New York, 1963, pp. 1-182.

10. Terzaghi, Karl, and Ralph Peck. Soil Mechanics in Engineering Practice. John Wiley & Sons, Inc., New York, 1967, pp. 46-173.

11. Whitman, Robert V., and William A. Bailey. Use of Computers For Slope Stability Analysis. Am. Soc. Civil Eng., Soil Mech. and Foundation Div., v. 93, No. SM4, July 1967, pp. 475-498.

APPENDIX A.--CASE I, HIGH PHREATIC LINE

SLOPE STABILITY ANALYSIS
SIMPLIFIED BISHOP METHOD

GALENA 3X1 SLOPE SAT C > 0

POINT DATA--USE 100 POINTS MAXIMUM

POINT NO.	X-COORD	Y-COORD
1	100.00	200.00
2	550.00	200.00
3	1165.00	400.00
4	1600.00	375.00
5	1600.00	200.00

LINE DATA---USE 100 LINES MAXIMUM

	POINT	POINT	SOIL
1	1	2	2
2	2	3	1
3	3	4	1
4	2	5	2

SOIL PROPERTIES--USE 10 SOILS OR LESS

SOIL NO.	DENSITY PCF	COH. PSI	TAN PHI	PP RATIO	PP RATIO CAPLRY
1	141.0	0.0	0.700	1.100	0.000
2	145.0	0.0	1.000	1.100	0.000

PHREATIC SURFACE POINTS--USE 10 POINTS MAXIMUM

	X-COORD	Y-COORD
1	100.000	200.000
2	550.000	200.000
3	850.000	300.000
4	1350.000	350.000
5	1600.000	350.000

THE FOLLOWING IS A PRINTOUT OF THE LINE ARRAY. THE INITIAL 3 LINES MUST BE THE SURFACE OF THE SLOPE GOING FROM LEFT TO RIGHT. THERE MUST BE NO VERTICAL LINES AFTER NO. 3 .

NO.	X-LEFT	Y-LEFT	X-RGHT	Y-RGHT	SLOPE	SOIL
1	100.00	200.00	550.00	200.00	0.0000	2
2	550.00	200.00	1165.00	400.00	0.3252	1
3	1165.00	400.00	1600.00	375.00	-0.0575	1
4	550.00	200.00	1600.00	200.00	0.0000	2

NUMBER OF SLICES--100 OR LESS

50.

THE LOWEST ELEVATION THAT SHOULD OCCUR ALONG
ANY TRIAL FAILURE SURFACE (YMIN.)
50.00

THE MINIMUM VALUE FOR THE GREATEST
DEPTH OF THE SLIDING MASS (DMIN).
0.00

1 COMPUTE USING AUTOMATIC SEARCH ROUTINE

2 COMPUTE USING PRESCRIBED CONTROL GRID

1

X AND Y COORDINATES OF THE CENTER OF
THE INITIAL TRIAL FAILURE SURFACE.

X = 650.00 Y = 725.00

INCREMENTS OF X AND Y USED IN THE COARSE GRID
IN SEARCHING FOR THE MINIMUM FACTOR OF SAFETY.
THE FINAL GRID IS 4 TIMES FINER.

X = 25.000 Y = 25.000

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FELLENIUS
650.00	725.00	675.00	35	3.220	2.521
650.00	725.00	673.28	35	3.205	2.513
650.00	725.00	656.13	33	3.026	2.410
650.00	725.00	638.98	32	2.846	2.304
650.00	725.00	621.83	30	2.673	2.204
650.00	725.00	604.67	28	2.503	2.106
650.00	725.00	587.52	26	2.328	2.003
650.00	725.00	570.37	24	2.148	1.891
650.00	725.00	553.21	21	1.922	1.731
650.00	725.00	536.06	18	1.704	1.564
650.00	725.00	518.91	15	1.402	1.315
650.00	725.00	501.75	12	1.346	1.289
650.00	725.00	484.60	9	1.242	1.214

THE LOWEST SAFETY FACTOR FOUND WAS 1.242 AT R= 484.60 .

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FELLENIUS
675.00	725.00	675.00	35	3.190	2.507
675.00	725.00	673.22	35	3.174	2.497
675.00	725.00	655.43	33	2.987	2.388
675.00	725.00	637.63	31	2.802	2.280
675.00	725.00	619.84	30	2.620	2.169
675.00	725.00	602.04	28	2.444	2.065
675.00	725.00	584.25	26	2.276	1.965
675.00	725.00	566.45	23	2.075	1.832
675.00	725.00	548.66	21	1.877	1.692
675.00	725.00	530.86	18	1.687	1.548
675.00	725.00	513.07	16	1.444	1.356
675.00	725.00	495.27	12	1.392	1.336
675.00	725.00	477.48	9	1.308	1.283

THE LOWEST SAFETY FACTOR FOUND WAS 1.308 AT R= 477.48 .

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FELLENIUS
625.00	725.00	675.00	35	3.313	2.579
625.00	725.00	673.35	35	3.298	2.571
625.00	725.00	656.84	33	3.127	2.476
625.00	725.00	640.33	32	2.960	2.385
625.00	725.00	623.81	30	2.797	2.297
625.00	725.00	607.30	28	2.626	2.200
625.00	725.00	590.79	26	2.445	2.093
625.00	725.00	574.28	24	2.216	1.941
625.00	725.00	557.77	21	2.008	1.802
625.00	725.00	541.26	18	1.746	1.602

625.00	725.00	524.75	15	1.365	1.279
625.00	725.00	508.24	13	1.300	1.241
625.00	725.00	491.72	9	1.183	1.150

THE LOWEST SAFETY FACTOR FOUND WAS 1.183 AT R= 491.72 .

600.00	725.00	675.00	35	3.405	2.644
600.00	725.00	673.41	35	3.393	2.638
600.00	725.00	657.54	34	3.235	2.556
600.00	725.00	641.67	32	3.080	2.477
600.00	725.00	625.80	30	2.917	2.389
600.00	725.00	609.93	28	2.744	2.290
600.00	725.00	594.07	26	2.559	2.181
600.00	725.00	578.20	24	2.362	2.058
600.00	725.00	562.33	22	2.096	1.868
600.00	725.00	546.46	19	1.850	1.691
600.00	725.00	530.59	15	1.487	1.387
600.00	725.00	514.72	12	1.272	1.213
600.00	725.00	498.85	9	1.152	1.118

THE LOWEST SAFETY FACTOR FOUND WAS 1.152 AT R= 498.85 .

575.00	725.00	675.00	36	3.542	2.748
575.00	725.00	673.48	35	3.531	2.743
575.00	725.00	658.25	33	3.386	2.674
575.00	725.00	643.02	32	3.234	2.597
575.00	725.00	627.79	30	3.071	2.509
575.00	725.00	612.57	28	2.899	2.413
575.00	725.00	597.34	26	2.715	2.305
575.00	725.00	582.11	24	2.510	2.175
575.00	725.00	566.88	22	2.277	2.016
575.00	725.00	551.65	19	1.958	1.771
575.00	725.00	536.43	16	1.645	1.529
575.00	725.00	521.20	12	1.238	1.177
575.00	725.00	505.97	8	1.146	1.113

THE LOWEST SAFETY FACTOR FOUND WAS 1.146 AT R= 505.97 .

550.00	725.00	675.00	35	3.726	2.893
550.00	725.00	673.54	35	3.715	2.888
550.00	725.00	658.96	33	3.575	2.823
550.00	725.00	644.37	32	3.424	2.748
550.00	725.00	629.78	30	3.303	2.689
550.00	725.00	615.20	28	3.137	2.601
550.00	725.00	600.61	26	2.958	2.499
550.00	725.00	586.02	24	2.753	2.371
550.00	725.00	571.44	22	2.523	2.218
550.00	725.00	556.85	20	2.201	1.976
550.00	725.00	542.27	17	1.868	1.721
550.00	725.00	527.68	13	1.321	1.251
550.00	725.00	513.09	8	1.149	1.117

THE LOWEST SAFETY FACTOR FOUND WAS 1.149 AT R= 513.09 .

575.00	750.00	700.00	36	3.498	2.741
575.00	750.00	698.47	36	3.486	2.735
575.00	750.00	683.14	34	3.338	2.659
575.00	750.00	667.81	32	3.187	2.580
575.00	750.00	652.48	30	3.064	2.519
575.00	750.00	637.15	29	2.898	2.426
575.00	750.00	621.82	27	2.714	2.316

575.00	750.00	606.49	25	2.473	2.155
575.00	750.00	591.16	23	2.245	1.998
575.00	750.00	575.83	20	1.984	1.808
575.00	750.00	560.50	17	1.569	1.461
575.00	750.00	545.17	12	1.247	1.191
575.00	750.00	529.84	9	1.141	1.110

THE LOWEST SAFETY FACTOR FOUND WAS 1.141 AT R= 529.84 .

575.00	775.00	725.00	36	3.492	2.754
575.00	775.00	723.46	36	3.447	2.729
575.00	775.00	708.03	35	3.328	2.667
575.00	775.00	692.59	34	3.180	2.589
575.00	775.00	677.16	32	3.024	2.505
575.00	775.00	661.73	30	2.858	2.408
575.00	775.00	646.30	28	2.679	2.300
575.00	775.00	630.87	25	2.442	2.139
575.00	775.00	615.44	23	2.218	1.984
575.00	775.00	600.01	20	1.961	1.796
575.00	775.00	584.57	17	1.555	1.456
575.00	775.00	569.14	13	1.261	1.210
575.00	775.00	553.71	9	1.144	1.114

THE LOWEST SAFETY FACTOR FOUND WAS 1.144 AT R= 553.71 .

600.00	750.00	700.00	36	3.376	2.649
600.00	750.00	698.40	36	3.363	2.642
600.00	750.00	682.43	34	3.202	2.554
600.00	750.00	666.46	33	3.041	2.465
600.00	750.00	650.49	30	2.880	2.377
600.00	750.00	634.52	28	2.711	2.280
600.00	750.00	618.55	27	2.532	2.172
600.00	750.00	602.57	25	2.335	2.047
600.00	750.00	586.60	23	2.071	1.855
600.00	750.00	570.63	20	1.827	1.677
600.00	750.00	554.66	15	1.477	1.383
600.00	750.00	538.69	12	1.276	1.220
600.00	750.00	522.72	9	1.164	1.132

THE LOWEST SAFETY FACTOR FOUND WAS 1.164 AT R= 522.72 .

550.00	750.00	700.00	36	3.667	2.874
550.00	750.00	698.53	36	3.657	2.870
550.00	750.00	683.84	34	3.551	2.821
550.00	750.00	669.16	32	3.405	2.748
550.00	750.00	654.47	30	3.252	2.670
550.00	750.00	639.78	29	3.086	2.577
550.00	750.00	625.09	27	2.908	2.472
550.00	750.00	610.40	25	2.708	2.347
550.00	750.00	595.72	23	2.483	2.196
550.00	750.00	581.03	21	2.163	1.952
550.00	750.00	566.34	18	1.827	1.690
550.00	750.00	551.65	13	1.261	1.199
550.00	750.00	536.96	9	1.145	1.115

THE LOWEST SAFETY FACTOR FOUND WAS 1.145 AT R= 536.96 .

581.25	750.00	700.00	36	3.454	2.709
581.25	750.00	698.45	36	3.443	2.703
581.25	750.00	682.96	35	3.323	2.643
581.25	750.00	667.47	32	3.173	2.566

581.25	750.00	651.98	31	3.016	2.482
581.25	750.00	636.49	29	2.846	2.385
581.25	750.00	621.00	27	2.664	2.276
581.25	750.00	605.51	25	2.424	2.114
581.25	750.00	590.02	23	2.198	1.959
581.25	750.00	574.53	20	1.940	1.772
581.25	750.00	559.04	17	1.540	1.437
581.25	750.00	543.55	12	1.257	1.202
581.25	750.00	528.06	9	1.144	1.111

THE LOWEST SAFETY FACTOR FOUND WAS 1.144 AT R= 528.06 .

568.75	750.00	700.00	36	3.542	2.773
568.75	750.00	698.48	36	3.531	2.767
568.75	750.00	683.31	34	3.389	2.698
568.75	750.00	668.14	33	3.238	2.620
568.75	750.00	652.98	31	3.080	2.534
568.75	750.00	637.81	29	2.912	2.439
568.75	750.00	622.64	27	2.732	2.332
568.75	750.00	607.47	25	2.527	2.199
568.75	750.00	592.30	23	2.297	2.041
568.75	750.00	577.13	21	1.981	1.796
568.75	750.00	561.96	17	1.607	1.492
568.75	750.00	546.79	12	1.239	1.182
568.75	750.00	531.62	8	1.143	1.111

THE LOWEST SAFETY FACTOR FOUND WAS 1.143 AT R= 531.62 .

575.00	756.25	706.25	36	3.488	2.739
575.00	756.25	704.71	36	3.477	2.734
575.00	756.25	689.36	35	3.326	2.654
575.00	756.25	674.00	32	3.211	2.599
575.00	756.25	658.65	30	3.054	2.515
575.00	756.25	643.29	29	2.887	2.421
575.00	756.25	627.94	27	2.705	2.312
575.00	756.25	612.58	25	2.465	2.150
575.00	756.25	597.23	23	2.238	1.994
575.00	756.25	581.87	20	1.978	1.805
575.00	756.25	566.52	17	1.566	1.460
575.00	756.25	551.16	12	1.250	1.195
575.00	756.25	535.81	9	1.142	1.110

THE LOWEST SAFETY FACTOR FOUND WAS 1.142 AT R= 535.81 .

575.00	743.75	693.75	36	3.508	2.742
575.00	743.75	692.22	36	3.496	2.736
575.00	743.75	676.92	34	3.350	2.663
575.00	743.75	661.61	32	3.198	2.584
575.00	743.75	646.31	30	3.039	2.497
575.00	743.75	631.00	28	2.907	2.429
575.00	743.75	615.70	27	2.687	2.292
575.00	743.75	600.39	25	2.482	2.159
575.00	743.75	585.09	23	2.253	2.002
575.00	743.75	569.79	20	1.990	1.811
575.00	743.75	554.48	17	1.573	1.463
575.00	743.75	539.18	12	1.244	1.187
575.00	743.75	523.87	8	1.142	1.110

THE LOWEST SAFETY FACTOR FOUND WAS 1.142 AT R= 523.87 .

THE MINIMUM FACTOR OF SAFETY IS 1.141 FOR X= 575.00 AND Y= 750.00.

APPENDIX B.--CASE II, LOW PHREATIC LINE

SLOPE STABILITY ANALYSIS
SIMPLIFIED BISHOP METHOD

GALENA 3X1 SLOPE WATER TABLE AT GROUND LEVEL

POINT DATA--USE 100 POINTS MAXIMUM

POINT NO.	X-COORD	Y-COORD
1	100.00	200.00
2	550.00	200.00
3	1165.00	400.00
4	1600.00	375.00
5	1600.00	200.00

LINE DATA---USE 100 LINES MAXIMUM

	POINT	POINT	SOIL
1	1	2	2
2	2	3	1
3	3	4	1
4	2	5	2

SOIL PROPERTIES--USE 10 SOILS OR LESS

SOIL NO.	DENSITY PCF	COH. PSI	TAN PHI	PP RATIO	PP RATIO CAPLRY
1	110.0	3.5	0.700	1.100	0.000
2	145.0	0.0	1.000	1.100	0.000

PHREATIC SURFACE POINTS--USE 10 POINTS MAXIMUM

	X-COORD	Y-COORD
1	100.000	200.000
2	1600.000	200.000

THE FOLLOWING IS A PRINTOUT OF THE LINE ARRAY. THE INITIAL 3 LINES MUST BE THE SURFACE OF THE SLOPE GOING FROM LEFT TO RIGHT. THERE MUST BE NO VERTICAL LINES AFTER NO. 3 .

NO.	X-LEFT	Y-LEFT	X-RGHT	Y-RGHT	SLOPE	SOIL
1	100.00	200.00	550.00	200.00	0.0000	2
2	550.00	200.00	1165.00	400.00	0.3252	1
3	1165.00	400.00	1600.00	375.00	-0.0575	1
4	550.00	200.00	1600.00	200.00	0.0000	2

NUMBER OF SLICES--100 OR LESS

50.

THE LOWEST FLEVATION THAT SHOULD OCCUR ALONG
ANY TRIAL FAILURE SURFACE (YMIN.)
50.00

THE MINIMUM VALUE FOR THE GREATEST
DEPTH OF THE SLIDING MASS (DMIN).
0.00

1 COMPUTE USING AUTOMATIC SEARCH ROUTINE
2 COMPUTE USING PRESCRIBED CONTROL GRID

1

X AND Y COORDINATES OF THE CENTER OF
THE INITIAL TRIAL FAILURE SURFACE.

X = 650.00 Y = 725.00

INCREMENTS OF X AND Y USED IN THE COARSE GRID
IN SEARCHING FOR THE MINIMUM FACTOR OF SAFETY.
THE FINAL GRID IS 4 TIMES FINER.

X = 25.000 Y = 25.000

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FLNIUS
650.00	725.00	675.00	35	4.441	3.693
650.00	725.00	673.28	35	4.423	3.683
650.00	725.00	656.13	33	4.210	3.559
650.00	725.00	638.98	32	4.006	3.440
650.00	725.00	621.83	30	3.813	3.332
650.00	725.00	604.67	28	3.635	3.235
650.00	725.00	587.52	26	3.464	3.143
650.00	725.00	570.37	24	3.303	3.055
650.00	725.00	553.21	21	3.099	2.917
650.00	725.00	536.06	18	2.961	2.826
650.00	725.00	518.91	15	2.824	2.726
650.00	725.00	501.75	12	2.983	2.917
650.00	725.00	531.77	18	2.923	2.795
650.00	725.00	527.48	16	2.889	2.770
650.00	725.00	523.20	16	2.806	2.700
650.00	725.00	514.62	14	2.848	2.758
650.00	725.00	510.33	14	2.881	2.800
650.00	725.00	506.04	13	2.925	2.851
650.00	725.00	484.60	9	3.608	3.576

THE LOWEST SAFETY FACTOR FOUND WAS 2.806 AT R= 523.20 .

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FLNIUS
675.00	725.00	675.00	35	4.406	3.677
675.00	725.00	673.22	35	4.388	3.666
675.00	725.00	655.43	33	4.164	3.534
675.00	725.00	637.63	31	3.949	3.405
675.00	725.00	619.84	30	3.746	3.285
675.00	725.00	602.04	28	3.561	3.178
675.00	725.00	584.25	26	3.402	3.094
675.00	725.00	566.45	23	3.205	2.968
675.00	725.00	548.66	21	3.044	2.862
675.00	725.00	530.86	18	2.969	2.824
675.00	725.00	513.07	16	2.818	2.716
675.00	725.00	495.27	12	2.967	2.899
675.00	725.00	526.41	17	2.854	2.721
675.00	725.00	521.97	16	2.791	2.672
675.00	725.00	517.52	16	2.803	2.692
675.00	725.00	508.62	14	2.842	2.747
675.00	725.00	504.17	14	2.871	2.785
675.00	725.00	499.72	14	2.911	2.834
675.00	725.00	477.48	9	3.566	3.532

THE LOWEST SAFETY FACTOR FOUND WAS 2.791 AT R= 521.97 .

X-COORD	Y-COORD	RADIUS	NO SLICES	FS BISHOP	FS FLNIUS
700.00	725.00	675.00	36	4.406	3.691

700.00	725.00	673.16	36	4.387	3.680
700.00	725.00	654.72	34	4.156	3.541
700.00	725.00	636.28	31	3.935	3.407
700.00	725.00	617.85	29	3.727	3.280
700.00	725.00	599.41	28	3.538	3.169
700.00	725.00	580.97	26	3.322	3.026
700.00	725.00	562.54	23	3.208	2.972
700.00	725.00	544.10	21	3.100	2.909
700.00	725.00	525.66	18	2.867	2.719
700.00	725.00	507.23	15	2.815	2.707
700.00	725.00	488.79	13	2.953	2.881
700.00	725.00	521.06	17	2.785	2.651
700.00	725.00	516.45	17	2.792	2.666
700.00	725.00	511.84	16	2.801	2.684
700.00	725.00	502.62	15	2.836	2.737
700.00	725.00	498.01	14	2.863	2.773
700.00	725.00	493.40	13	2.900	2.819
700.00	725.00	470.36	9	3.525	3.490

THE LOWEST SAFETY FACTOR FOUND WAS 2.785 AT R= 521.06 .

725.00	725.00	675.00	35	4.438	3.731
725.00	725.00	673.09	35	4.419	3.721
725.00	725.00	654.01	34	4.182	3.577
725.00	725.00	634.94	32	3.958	3.441
725.00	725.00	615.86	29	3.750	3.313
725.00	725.00	596.78	27	3.505	3.148
725.00	725.00	577.70	26	3.348	3.055
725.00	725.00	558.62	23	3.190	2.949
725.00	725.00	539.54	21	3.104	2.903
725.00	725.00	520.47	18	2.785	2.636
725.00	725.00	501.39	15	2.814	2.700
725.00	725.00	534.78	19	3.053	2.859
725.00	725.00	530.01	19	2.990	2.808
725.00	725.00	525.24	19	2.830	2.668
725.00	725.00	515.70	17	2.788	2.647
725.00	725.00	510.93	17	2.793	2.661
725.00	725.00	506.16	17	2.800	2.678
725.00	725.00	482.31	13	2.940	2.864
725.00	725.00	463.23	9	3.487	3.450

THE LOWEST SAFETY FACTOR FOUND WAS 2.785 AT R= 520.47 .

700.00	750.00	700.00	36	4.414	3.726
700.00	750.00	698.15	36	4.394	3.714
700.00	750.00	679.61	34	4.159	3.569
700.00	750.00	661.07	33	3.933	3.427
700.00	750.00	642.53	31	3.720	3.294
700.00	750.00	623.99	28	3.525	3.172
700.00	750.00	605.46	26	3.302	3.019
700.00	750.00	586.92	24	3.177	2.951
700.00	750.00	568.38	21	3.071	2.889
700.00	750.00	549.84	18	2.766	2.630
700.00	750.00	531.30	16	2.802	2.699
700.00	750.00	563.74	21	3.026	2.852
700.00	750.00	559.11	20	2.977	2.812
700.00	750.00	554.48	19	2.918	2.764
700.00	750.00	545.21	18	2.770	2.642
700.00	750.00	540.57	17	2.776	2.656
700.00	750.00	535.94	16	2.788	2.676
700.00	750.00	512.76	13	2.941	2.872

700.00	750.00	494.23	10	3.511	3.477

THE LOWEST SAFETY FACTOR FOUND WAS 2.766 AT R= 549.84 .

700.00	775.00	725.00	37	4.470	3.796
700.00	775.00	723.14	36	4.452	3.785
700.00	775.00	704.50	35	4.215	3.638
700.00	775.00	685.86	33	3.938	3.453
700.00	775.00	667.22	31	3.720	3.312
700.00	775.00	648.58	30	3.518	3.181
700.00	775.00	629.94	27	3.344	3.072
700.00	775.00	611.30	24	3.154	2.939
700.00	775.00	592.66	22	3.045	2.870
700.00	775.00	574.02	19	2.751	2.620
700.00	775.00	555.38	16	2.790	2.691
700.00	775.00	588.00	21	3.001	2.834
700.00	775.00	583.34	20	2.954	2.796
700.00	775.00	578.68	20	2.898	2.750
700.00	775.00	569.36	18	2.756	2.633
700.00	775.00	564.70	18	2.764	2.649
700.00	775.00	560.04	17	2.774	2.667
700.00	775.00	536.74	13	2.931	2.865
700.00	775.00	518.10	10	3.504	3.471

THE LOWEST SAFETY FACTOR FOUND WAS 2.751 AT R= 574.02 .

700.00	800.00	750.00	37	4.484	3.833
700.00	800.00	748.13	37	4.464	3.821
700.00	800.00	729.38	35	4.225	3.669
700.00	800.00	710.64	33	3.994	3.520
700.00	800.00	691.90	32	3.725	3.333
700.00	800.00	673.16	30	3.518	3.195
700.00	800.00	654.42	27	3.337	3.077
700.00	800.00	635.68	24	3.139	2.932
700.00	800.00	616.93	23	3.020	2.852
700.00	800.00	598.19	19	2.739	2.613
700.00	800.00	579.45	17	2.778	2.683
700.00	800.00	612.25	22	2.979	2.818
700.00	800.00	607.56	21	2.933	2.780
700.00	800.00	602.88	20	2.879	2.737
700.00	800.00	593.51	19	2.744	2.625
700.00	800.00	588.82	18	2.752	2.641
700.00	800.00	584.14	17	2.763	2.660
700.00	800.00	560.71	13	2.921	2.858
700.00	800.00	541.97	9	3.493	3.462

THE LOWEST SAFETY FACTOR FOUND WAS 2.739 AT R= 598.19 .

700.00	825.00	775.00	38	4.525	3.890
700.00	825.00	773.12	38	4.481	3.859
700.00	825.00	754.27	37	4.238	3.702
700.00	825.00	735.43	34	4.005	3.548
700.00	825.00	716.59	32	3.782	3.400
700.00	825.00	697.74	30	3.522	3.212
700.00	825.00	678.90	28	3.334	3.085
700.00	825.00	660.06	26	3.130	2.933
700.00	825.00	641.21	23	3.003	2.841
700.00	825.00	622.37	20	2.726	2.605
700.00	825.00	603.53	17	2.768	2.676
700.00	825.00	636.50	23	2.959	2.804
700.00	825.00	631.79	22	2.914	2.766

700.00	825.00	627.08	21	2.863	2.724
700.00	825.00	617.66	19	2.732	2.618
700.00	825.00	612.95	19	2.741	2.634
700.00	825.00	608.24	18	2.751	2.652
700.00	825.00	584.68	14	2.911	2.850
700.00	825.00	565.84	10	3.480	3.450

THE LOWEST SAFETY FACTOR FOUND WAS 2.726 AT R= 622.37 .

700.00	850.00	800.00	39	4.544	3.930
700.00	850.00	798.11	39	4.524	3.917
700.00	850.00	779.16	37	4.256	3.737
700.00	850.00	760.22	35	4.019	3.578
700.00	850.00	741.27	32	3.792	3.425
700.00	850.00	722.33	31	3.582	3.281
700.00	850.00	703.38	28	3.337	3.098
700.00	850.00	684.44	26	3.127	2.938
700.00	850.00	665.49	23	2.992	2.836
700.00	850.00	646.54	20	2.715	2.598
700.00	850.00	627.60	18	2.758	2.669
700.00	850.00	660.75	22	2.946	2.796
700.00	850.00	656.02	22	2.899	2.756
700.00	850.00	651.28	21	2.780	2.650
700.00	850.00	641.81	20	2.721	2.611
700.00	850.00	637.07	19	2.730	2.627
700.00	850.00	632.34	18	2.742	2.646
700.00	850.00	608.65	14	2.903	2.844
700.00	850.00	589.71	10	3.472	3.443

THE LOWEST SAFETY FACTOR FOUND WAS 2.715 AT R= 646.54 .

700.00	875.00	825.00	39	4.567	3.971
700.00	875.00	823.10	39	4.546	3.958
700.00	875.00	804.05	37	4.325	3.815
700.00	875.00	785.00	36	4.036	3.610
700.00	875.00	765.95	34	3.806	3.452
700.00	875.00	746.91	31	3.591	3.302
700.00	875.00	727.86	29	3.343	3.114
700.00	875.00	708.81	26	3.128	2.947
700.00	875.00	689.77	24	2.986	2.837
700.00	875.00	670.72	21	2.705	2.592
700.00	875.00	651.67	18	2.749	2.664
700.00	875.00	685.01	22	2.939	2.795
700.00	875.00	680.24	22	2.890	2.752
700.00	875.00	675.48	21	2.771	2.646
700.00	875.00	665.96	21	2.711	2.604
700.00	875.00	661.20	19	2.720	2.620
700.00	875.00	656.44	18	2.732	2.639
700.00	875.00	632.63	14	2.894	2.837
700.00	875.00	613.58	10	3.462	3.434

THE LOWEST SAFETY FACTOR FOUND WAS 2.705 AT R= 670.72 .

700.00	900.00	850.00	41	4.639	4.051
700.00	900.00	848.09	40	4.572	4.000
700.00	900.00	828.94	38	4.345	3.850
700.00	900.00	809.79	36	4.105	3.687
700.00	900.00	790.64	34	3.822	3.480
700.00	900.00	771.49	31	3.603	3.325
700.00	900.00	752.34	30	3.352	3.131
700.00	900.00	733.19	27	3.133	2.959

700.00	900.00	714.05	24	2.987	2.843
700.00	900.00	694.90	21	2.700	2.591
700.00	900.00	675.75	18	2.740	2.657
700.00	900.00	709.26	23	2.937	2.798
700.00	900.00	704.47	22	2.886	2.754
700.00	900.00	699.68	21	2.703	2.587
700.00	900.00	690.11	21	2.702	2.599
700.00	900.00	685.32	20	2.710	2.614
700.00	900.00	680.54	19	2.723	2.634
700.00	900.00	656.60	15	2.886	2.831
700.00	900.00	637.45	11	3.452	3.425

THE LOWEST SAFETY FACTOR FOUND WAS 2.700 AT R= 694.90 .

700.00	925.00	875.00	41	4.664	4.091
700.00	925.00	873.07	41	4.644	4.079
700.00	925.00	853.82	39	4.369	3.888
700.00	925.00	834.57	36	4.125	3.720
700.00	925.00	815.32	35	3.840	3.509
700.00	925.00	796.07	32	3.618	3.349
700.00	925.00	776.82	30	3.363	3.151
700.00	925.00	757.57	27	3.141	2.974
700.00	925.00	738.32	24	2.991	2.852
700.00	925.00	719.07	21	2.700	2.595
700.00	925.00	699.82	19	2.732	2.652
700.00	925.00	733.51	23	2.940	2.806
700.00	925.00	728.70	23	2.831	2.706
700.00	925.00	723.89	22	2.705	2.594
700.00	925.00	714.26	21	2.700	2.600
700.00	925.00	709.45	20	2.704	2.610
700.00	925.00	704.64	20	2.714	2.627
700.00	925.00	680.57	15	2.879	2.825
700.00	925.00	661.32	11	3.445	3.419

THE LOWEST SAFETY FACTOR FOUND WAS 2.700 AT R= 714.26 .

700.00	950.00	900.00	41	4.691	4.134
700.00	950.00	898.06	41	4.670	4.120
700.00	950.00	878.71	40	4.418	3.948
700.00	950.00	859.36	37	4.147	3.754
700.00	950.00	840.01	35	3.911	3.586
700.00	950.00	820.66	33	3.634	3.375
700.00	950.00	801.30	30	3.377	3.173
700.00	950.00	781.95	27	3.151	2.990
700.00	950.00	762.60	24	2.997	2.864
700.00	950.00	743.25	22	2.704	2.602
700.00	950.00	723.90	20	2.723	2.645
700.00	950.00	757.76	23	2.945	2.817
700.00	950.00	752.93	23	2.837	2.717
700.00	950.00	748.09	22	2.712	2.604
700.00	950.00	738.41	21	2.701	2.605
700.00	950.00	733.57	20	2.702	2.612
700.00	950.00	728.74	20	2.709	2.624
700.00	950.00	704.55	16	2.871	2.819
700.00	950.00	685.19	11	3.436	3.410

THE LOWEST SAFETY FACTOR FOUND WAS 2.701 AT R= 738.41 .

725.00	925.00	875.00	41	4.726	4.158
725.00	925.00	873.01	41	4.706	4.146
725.00	925.00	853.12	39	4.406	3.935

725.00	925.00	833.23	36	4.187	3.788
725.00	925.00	813.33	34	3.900	3.576
725.00	925.00	793.44	31	3.684	3.422
725.00	925.00	773.55	30	3.438	3.230
725.00	925.00	753.66	27	3.236	3.068
725.00	925.00	733.77	24	3.045	2.901
725.00	925.00	713.88	21	2.733	2.625
725.00	925.00	693.98	19	2.730	2.646
725.00	925.00	674.09	15	2.865	2.809
725.00	925.00	708.90	21	2.725	2.622
725.00	925.00	703.93	20	2.721	2.624
725.00	925.00	698.96	19	2.722	2.632
725.00	925.00	689.01	19	2.747	2.670
725.00	925.00	684.04	17	2.776	2.706
725.00	925.00	679.06	16	2.814	2.751
725.00	925.00	654.20	11	3.408	3.381

THE LOWEST SAFETY FACTOR FOUND WAS 2.721 AT R= 703.93 .

675.00	925.00	875.00	41	4.621	4.042
675.00	925.00	873.14	41	4.601	4.029
675.00	925.00	854.53	38	4.330	3.841
675.00	925.00	835.92	37	4.089	3.674
675.00	925.00	817.31	35	3.856	3.511
675.00	925.00	798.71	33	3.583	3.305
675.00	925.00	780.10	30	3.374	3.154
675.00	925.00	761.49	27	3.139	2.969
675.00	925.00	742.88	25	2.959	2.826
675.00	925.00	724.27	22	2.687	2.585
675.00	925.00	705.66	18	2.738	2.662
675.00	925.00	738.23	23	2.902	2.775
675.00	925.00	733.58	23	2.860	2.738
675.00	925.00	728.92	22	2.822	2.707
675.00	925.00	719.62	21	2.694	2.598
675.00	925.00	714.97	20	2.705	2.616
675.00	925.00	710.31	19	2.719	2.636
675.00	925.00	687.05	15	2.894	2.843
675.00	925.00	668.45	10	3.484	3.459

THE LOWEST SAFETY FACTOR FOUND WAS 2.687 AT R= 724.27 .

650.00	925.00	875.00	40	4.623	4.030
650.00	925.00	873.20	40	4.604	4.018
650.00	925.00	855.24	39	4.316	3.816
650.00	925.00	837.27	37	4.079	3.652
650.00	925.00	819.30	35	3.849	3.490
650.00	925.00	801.34	33	3.628	3.334
650.00	925.00	783.37	31	3.367	3.135
650.00	925.00	765.40	28	3.180	3.001
650.00	925.00	747.44	25	2.926	2.792
650.00	925.00	729.47	22	2.789	2.686
650.00	925.00	711.50	18	2.746	2.672
650.00	925.00	693.54	15	2.910	2.861
650.00	925.00	724.98	20	2.697	2.606
650.00	925.00	720.49	20	2.709	2.624
650.00	925.00	715.99	19	2.725	2.645
650.00	925.00	707.01	18	2.772	2.705
650.00	925.00	702.52	16	2.806	2.745
650.00	925.00	698.03	16	2.852	2.797
650.00	925.00	675.57	10	3.524	3.500

THE LOWEST SAFETY FACTOR FOUND WAS 2.697 AT R= 724.98 .

675.00	950.00	900.00	42	4.645	4.081
675.00	950.00	898.13	42	4.624	4.068
675.00	950.00	879.42	40	4.353	3.877
675.00	950.00	860.71	37	4.108	3.705
675.00	950.00	842.00	35	3.871	3.537
675.00	950.00	823.29	33	3.596	3.327
675.00	950.00	804.58	31	3.382	3.170
675.00	950.00	785.87	28	3.144	2.980
675.00	950.00	767.16	25	2.959	2.831
675.00	950.00	748.45	22	2.683	2.584
675.00	950.00	729.74	18	2.730	2.656
675.00	950.00	762.48	24	2.901	2.779
675.00	950.00	757.80	23	2.858	2.741
675.00	950.00	753.12	22	2.775	2.664
675.00	950.00	743.77	21	2.687	2.594
675.00	950.00	739.09	21	2.696	2.609
675.00	950.00	734.41	20	2.712	2.631
675.00	950.00	711.03	16	2.887	2.837
675.00	950.00	692.32	11	3.473	3.449

THE LOWEST SAFETY FACTOR FOUND WAS 2.683 AT R= 748.45 .

675.00	975.00	925.00	42	4.672	4.123
675.00	975.00	923.12	42	4.651	4.109
675.00	975.00	904.31	40	4.423	3.954
675.00	975.00	885.49	38	4.129	3.738
675.00	975.00	866.68	36	3.888	3.564
675.00	975.00	847.87	34	3.660	3.398
675.00	975.00	829.06	31	3.393	3.188
675.00	975.00	810.25	28	3.151	2.993
675.00	975.00	791.44	25	2.963	2.839
675.00	975.00	772.62	22	2.683	2.588
675.00	975.00	753.81	19	2.724	2.651
675.00	975.00	786.73	24	2.905	2.786
675.00	975.00	782.03	24	2.861	2.748
675.00	975.00	777.33	23	2.775	2.668
675.00	975.00	767.92	21	2.684	2.594
675.00	975.00	763.22	21	2.690	2.606
675.00	975.00	758.51	21	2.703	2.625
675.00	975.00	735.00	15	2.880	2.832
675.00	975.00	716.19	11	3.465	3.442

THE LOWEST SAFETY FACTOR FOUND WAS 2.683 AT R= 772.62 .

700.00	950.00	900.00	41	4.691	4.134
700.00	950.00	898.06	41	4.670	4.120
700.00	950.00	878.71	40	4.418	3.948
700.00	950.00	859.36	37	4.147	3.754
700.00	950.00	840.01	35	3.911	3.586
700.00	950.00	820.66	33	3.634	3.375
700.00	950.00	801.30	30	3.377	3.173
700.00	950.00	781.95	27	3.151	2.990
700.00	950.00	762.60	24	2.997	2.864
700.00	950.00	743.25	22	2.704	2.602
700.00	950.00	723.90	20	2.723	2.645
700.00	950.00	757.76	23	2.945	2.817
700.00	950.00	752.93	23	2.837	2.717
700.00	950.00	748.09	22	2.712	2.604
700.00	950.00	738.41	21	2.701	2.605

700.00	950.00	733.57	20	2.702	2.612
700.00	950.00	728.74	20	2.709	2.624
700.00	950.00	704.55	16	2.871	2.819
700.00	950.00	685.19	11	3.436	3.410

THE LOWEST SAFETY FACTOR FOUND WAS 2.701 AT R= 738.41 .

650.00	950.00	900.00	42	4.642	4.065
650.00	950.00	898.19	42	4.623	4.053
650.00	950.00	880.12	40	4.380	3.887
650.00	950.00	862.06	37	4.143	3.722
650.00	950.00	843.99	35	3.860	3.513
650.00	950.00	825.92	34	3.634	3.351
650.00	950.00	807.85	31	3.370	3.147
650.00	950.00	789.78	28	3.177	3.005
650.00	950.00	771.71	25	2.917	2.788
650.00	950.00	753.64	23	2.780	2.680
650.00	950.00	735.58	19	2.738	2.667
650.00	950.00	717.51	15	2.904	2.856
650.00	950.00	749.13	21	2.689	2.600
650.00	950.00	744.61	20	2.701	2.618
650.00	950.00	740.09	19	2.717	2.640
650.00	950.00	731.06	17	2.765	2.700
650.00	950.00	726.54	17	2.799	2.740
650.00	950.00	722.02	16	2.844	2.791
650.00	950.00	699.44	11	3.515	3.492

THE LOWEST SAFETY FACTOR FOUND WAS 2.689 AT R= 749.13 .

681.25	950.00	900.00	42	4.644	4.085
681.25	950.00	898.11	42	4.623	4.071
681.25	950.00	879.24	39	4.397	3.919
681.25	950.00	860.37	37	4.104	3.705
681.25	950.00	841.50	35	3.866	3.535
681.25	950.00	822.63	33	3.640	3.373
681.25	950.00	803.76	31	3.378	3.168
681.25	950.00	784.89	28	3.142	2.980
681.25	950.00	766.02	24	2.964	2.835
681.25	950.00	747.15	22	2.687	2.587
681.25	950.00	728.28	19	2.729	2.653
681.25	950.00	761.30	24	2.910	2.786
681.25	950.00	756.58	23	2.868	2.748
681.25	950.00	751.87	22	2.770	2.659
681.25	950.00	742.43	21	2.688	2.594
681.25	950.00	737.71	21	2.696	2.608
681.25	950.00	732.99	20	2.710	2.629
681.25	950.00	709.41	15	2.883	2.833
681.25	950.00	690.54	11	3.464	3.439

THE LOWEST SAFETY FACTOR FOUND WAS 2.687 AT R= 747.15 .

668.75	950.00	900.00	41	4.648	4.080
668.75	950.00	898.15	41	4.628	4.067
668.75	950.00	879.60	40	4.356	3.877
668.75	950.00	861.05	38	4.114	3.707
668.75	950.00	842.50	35	3.878	3.540
668.75	950.00	823.95	33	3.602	3.330
668.75	950.00	805.40	30	3.389	3.174
668.75	950.00	786.85	28	3.148	2.983
668.75	950.00	768.30	25	2.957	2.829
668.75	950.00	749.75	22	2.680	2.582

668.75	950.00	731.20	18	2.733	2.659
668.75	950.00	763.66	24	2.897	2.775
668.75	950.00	759.02	23	2.849	2.733
668.75	950.00	754.38	22	2.814	2.704
668.75	950.00	745.11	21	2.686	2.594
668.75	950.00	740.47	20	2.698	2.612
668.75	950.00	735.83	20	2.713	2.633
668.75	950.00	712.65	16	2.891	2.841
668.75	950.00	694.10	10	3.485	3.461

THE LOWEST SAFETY FACTOR FOUND WAS 2.680 AT R= 749.75 .

662.50	950.00	900.00	41	4.653	4.081
662.50	950.00	898.16	41	4.609	4.048
662.50	950.00	879.77	39	4.362	3.878
662.50	950.00	861.38	38	4.121	3.710
662.50	950.00	842.99	36	3.888	3.545
662.50	950.00	824.60	33	3.611	3.335
662.50	950.00	806.21	31	3.399	3.180
662.50	950.00	787.82	28	3.155	2.988
662.50	950.00	769.44	25	2.906	2.777
662.50	950.00	751.05	22	2.739	2.637
662.50	950.00	732.66	19	2.735	2.662
662.50	950.00	714.27	15	2.895	2.846
662.50	950.00	746.45	22	2.687	2.596
662.50	950.00	741.85	20	2.699	2.614
662.50	950.00	737.25	19	2.714	2.635
662.50	950.00	728.06	18	2.760	2.693
662.50	950.00	723.46	17	2.794	2.733
662.50	950.00	718.86	16	2.837	2.782
662.50	950.00	695.88	11	3.495	3.472

THE LOWEST SAFETY FACTOR FOUND WAS 2.687 AT R= 746.45 .

668.75	956.25	906.25	41	4.654	4.090
668.75	956.25	904.39	41	4.634	4.077
668.75	956.25	885.82	40	4.362	3.886
668.75	956.25	867.24	38	4.118	3.715
668.75	956.25	848.67	35	3.882	3.547
668.75	956.25	830.09	33	3.605	3.336
668.75	956.25	811.52	30	3.391	3.178
668.75	956.25	792.94	28	3.150	2.986
668.75	956.25	774.37	25	2.957	2.831
668.75	956.25	755.79	22	2.679	2.582
668.75	956.25	737.22	18	2.731	2.657
668.75	956.25	769.72	24	2.897	2.776
668.75	956.25	765.08	23	2.849	2.734
668.75	956.25	760.43	22	2.814	2.704
668.75	956.25	751.15	21	2.685	2.593
668.75	956.25	746.50	21	2.696	2.610
668.75	956.25	741.86	20	2.711	2.632
668.75	956.25	718.64	16	2.889	2.840
668.75	956.25	700.06	10	3.482	3.458

THE LOWEST SAFETY FACTOR FOUND WAS 2.679 AT R= 755.79 .

668.75	962.50	912.50	42	4.660	4.100
668.75	962.50	910.64	42	4.640	4.086
668.75	962.50	892.04	40	4.368	3.895
668.75	962.50	873.44	38	4.123	3.723
668.75	962.50	854.84	35	3.886	3.553

668.75	962.50	836.24	33	3.609	3.341
668.75	962.50	817.64	31	3.394	3.182
668.75	962.50	799.04	29	3.151	2.989
668.75	962.50	780.44	25	2.958	2.832
668.75	962.50	761.83	22	2.679	2.583
668.75	962.50	743.23	18	2.729	2.656
668.75	962.50	775.78	24	2.897	2.778
668.75	962.50	771.13	23	2.849	2.735
668.75	962.50	766.48	22	2.813	2.704
668.75	962.50	757.18	21	2.683	2.593
668.75	962.50	752.53	21	2.693	2.609
668.75	962.50	747.88	20	2.709	2.631
668.75	962.50	724.63	16	2.887	2.839
668.75	962.50	706.03	11	3.479	3.455

THE LOWEST SAFETY FACTOR FOUND WAS 2.679 AT R= 761.83 .

668.75	968.75	918.75	42	4.667	4.110
668.75	968.75	916.89	42	4.646	4.096
668.75	968.75	898.26	40	4.374	3.904
668.75	968.75	879.64	38	4.128	3.731
668.75	968.75	861.01	35	3.890	3.560
668.75	968.75	842.38	33	3.612	3.347
668.75	968.75	823.76	31	3.396	3.187
668.75	968.75	805.13	29	3.152	2.992
668.75	968.75	786.50	25	2.906	2.781
668.75	968.75	767.88	22	2.679	2.583
668.75	968.75	749.25	19	2.727	2.655
668.75	968.75	781.85	24	2.897	2.779
668.75	968.75	777.19	24	2.849	2.736
668.75	968.75	772.54	22	2.812	2.704
668.75	968.75	763.22	21	2.682	2.592
668.75	968.75	758.57	21	2.691	2.607
668.75	968.75	753.91	20	2.708	2.630
668.75	968.75	730.63	16	2.886	2.838
668.75	968.75	712.00	11	3.477	3.454

THE LOWEST SAFETY FACTOR FOUND WAS 2.679 AT R= 767.88 .

668.75	975.00	925.00	42	4.674	4.120
668.75	975.00	923.13	42	4.652	4.106
668.75	975.00	904.48	40	4.428	3.955
668.75	975.00	885.83	38	4.133	3.739
668.75	975.00	867.18	36	3.894	3.567
668.75	975.00	848.53	34	3.616	3.353
668.75	975.00	829.88	31	3.399	3.191
668.75	975.00	811.23	29	3.154	2.995
668.75	975.00	792.57	25	2.907	2.783
668.75	975.00	773.92	22	2.679	2.584
668.75	975.00	755.27	19	2.725	2.654
668.75	975.00	787.91	24	2.898	2.781
668.75	975.00	783.25	24	2.850	2.738
668.75	975.00	778.59	22	2.770	2.663
668.75	975.00	769.26	21	2.682	2.592
668.75	975.00	764.60	21	2.690	2.606
668.75	975.00	759.93	21	2.706	2.628
668.75	975.00	736.62	16	2.884	2.837
668.75	975.00	717.97	11	3.475	3.452

THE LOWEST SAFETY FACTOR FOUND WAS 2.679 AT R= 773.92 .

675.00	968.75	918.75	42	4.665	4.113
675.00	968.75	916.87	42	4.644	4.098
675.00	968.75	898.08	40	4.417	3.945
675.00	968.75	879.30	38	4.124	3.730
675.00	968.75	860.51	35	3.884	3.557
675.00	968.75	841.73	34	3.657	3.392
675.00	968.75	822.94	31	3.390	3.184
675.00	968.75	804.15	28	3.149	2.990
675.00	968.75	785.37	25	2.961	2.836
675.00	968.75	766.58	22	2.683	2.586
675.00	968.75	747.79	19	2.725	2.652
675.00	968.75	780.67	24	2.904	2.784
675.00	968.75	775.97	24	2.860	2.746
675.00	968.75	771.28	22	2.775	2.667
675.00	968.75	761.88	21	2.684	2.594
675.00	968.75	757.19	21	2.691	2.606
675.00	968.75	752.49	21	2.705	2.626
675.00	968.75	729.01	15	2.882	2.833
675.00	968.75	710.22	11	3.467	3.444

THE LOWEST SAFETY FACTOR FOUND WAS 2.683 AT R= 766.58 .

662.50	968.75	918.75	42	4.670	4.110
662.50	968.75	916.90	41	4.650	4.096
662.50	968.75	898.44	40	4.378	3.905
662.50	968.75	879.97	38	4.135	3.733
662.50	968.75	861.51	36	3.898	3.564
662.50	968.75	843.04	33	3.620	3.351
662.50	968.75	824.58	31	3.404	3.191
662.50	968.75	806.11	29	3.158	2.995
662.50	968.75	787.64	25	2.906	2.781
662.50	968.75	769.18	22	2.725	2.627
662.50	968.75	750.71	18	2.729	2.658
662.50	968.75	783.03	25	2.894	2.777
662.50	968.75	778.41	23	2.842	2.730
662.50	968.75	773.79	23	2.808	2.701
662.50	968.75	764.56	22	2.681	2.592
662.50	968.75	759.95	21	2.693	2.610
662.50	968.75	755.33	20	2.709	2.632
662.50	968.75	732.25	16	2.890	2.842
662.50	968.75	713.78	11	3.488	3.465

THE LOWEST SAFETY FACTOR FOUND WAS 2.681 AT R= 764.56 .

THE MINIMUM FACTOR OF SAFETY IS 2.679 FOR X= 668.75 AND Y= 968.75.

☆U. S. GOVERNMENT PRINTING OFFICE : 1969 O - 33f

IC bureau of mines information circular 8411

SUPPLY AND DEMAND FOR ENERGY IN THE UNITED STATES BY STATES AND REGIONS, 1960 AND 1965

(In Four Parts)

4. Petroleum and Natural Gas Liquids

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

1969

SUPPLY AND DEMAND FOR ENERGY IN THE UNITED STATES BY STATES AND REGIONS, 1960 AND 1965

(In Four Parts)

4. Petroleum and Natural Gas Liquids

By Lulie H. Crump and Phillip N. Yasnowsky

* * * * * * * * * * * information circular 8411

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

Crump, Lulie H

Supply and demand for energy in the United States by States and regions, 1960 and 1965. (In four parts.) 4. Petroleum and natural gas liquids, by Lulie H. Crump and Phillip N. Yasnowsky. [Washington] U. S. Dept. of the Interior, Bureau of Mines [1969]

25 p. illus., tables. (U. S. Bureau of Mines. Information circular 8411)

1. Power resources—U.S. 2. Petroleum—U.S. 3. Gas, Natural—U.S. I. Yasnowsky, Phillip N., jt. auth. II. Title. (Series)

TN23.U71 no. 8411 622.06173

U. S. Dept. of the Int. Library

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price 55 cents

FOREWORD

Each year the Bureau of Mines features an annual energy balance by source, form, and end-use in the Minerals Yearbook. It has been suggested that this national balance would be improved if it were prepared within the context of prior State and regional balances, and interregional energy flows.

Unfortunately, supply and demand data on a State-by-State basis for various energy sources, forms, and markets are not readily available. This study attempts to correct this deficiency by constructing an energy model at the State and regional level and quantifying this with available data and information. The study is presented in four parts: (1) Coal, (2) Utility Electricity, (3) Natural Gas, and (4) Petroleum and Natural Gas Liquids. Data are shown for the years 1960 and 1965.

The State and regional commodity balances presented in the four parts of the study are compatible with and additive to the Bureau's national balances for 1960 and 1965 as shown in the Minerals Yearbook. This compatibility was achieved by using the national energy model as a base for the State and regional model; by standard presentation of energy components within a 50-State, three-region, and seven-subregion framework; and by the use of standard units as well as energy equivalents--British thermal units. The separate commodity balances and flows are also designed to serve as inputs for the construction of integrated energy balances at the State, regional, and national levels. These integrated balances will be the subject of a second study to be released at a later date.

WILLIAM A. VOGELY
Assistant Director--
Mineral Resource Evaluation

CONTENTS

ILLUSTRATIONS

TABLES

TABLES--Continued

SUPPLY AND DEMAND FOR ENERGY IN THE UNITED STATES BY STATES AND REGIONS, 1960 AND 1965

(In Four Parts)

4. Petroleum and Natural Gas Liquids

by

Lulie H. Crump[1] and Phillip N. Yasnowsky[2]

ABSTRACT

U.S. supply and demand data for petroleum and natural gas liquids, by States and regions, were tabulated for the years 1960 and 1965. Estimates are provided of State-by-State quantitative data for the petroleum and natural gas liquids industry that can be integrated into State, regional, and national energy balances by source, form, and consumer sectors, and used for determination of interstate and interregional energy flows. Tables 1-4 show the estimated total supply of petroleum available for consumption and the supply's distribution among the major consumer demand sectors (household and commercial, industrial, transportation, and electricity generation). To obtain summary figures for the major proportion of refined products by States, individual tables were compiled for the six major products (tables 5-16). To enable comparison of petroleum data with those for other energy forms, conventional volumetric data in barrels were converted to their British thermal unit (Btu) equivalents. Interregional shipments of crude petroleum and theoretical flow patterns for petroleum products are shown in figures 1-4.

INTRODUCTION

Supply and demand data on a State-by-State basis for various energy forms and markets have not been readily available for use by those engaged in energy analysis and forecasting. Much of the available major energy resources data is prepared on the basis of regional divisions peculiar to each industry. The primary purpose of this study is to provide, on a State-by-State basis, petroleum and natural gas liquids industry data that can be (1) integrated into State and regional energy balances by source, form, and consumer sectors, and (2) used to determine interstate and interregional energy flows.

Because the complexity of petroleum statistics exceeds that for other energy sources, a table is included (see appendix) describing the basic methodology used to develop the input data, presenting the computational

[1]Statistical assistant, Division of Mineral Economics, Bureau of Mines, Washington, D.C.
[2]Economist, Division of Mineral Economics, Bureau of Mines, Washington, D.C.

procedures and identifying source material. The primary energy source material is Bureau of Mines' petroleum and natural gas liquids data published annually in the Minerals Yearbook and Mineral Industry Surveys series.

METHODOLOGY

Regions and States

In this study, the United States was arbitrarily divided into three energy regions:

Region I Eastern United States:

Subregion Ia:

Maine	Pennsylvania	Georgia	
New Hampshire	Delaware	Florida	
Vermont	Maryland	Kentucky	
Massachusetts	District of Columbia	Tennessee	
Rhode Island	Virginia	Alabama	
Connecticut	West Virginia	Mississippi	
New York	North Carolina	Ohio	
New Jersey	South Carolina		

Subregion Ib:

Indiana
Illinois
Michigan
Wisconsin

Region II Central United States:

Subregion IIa:

Minnesota
Iowa
Missouri
North Dakota
South Dakota
Nebraska

Subregion IIb:

Arkansas
Louisiana
Oklahoma
Texas
New Mexico
Kansas

Region III Western United States:

Subregion IIIa:

Montana
Idaho
Wyoming
Utah
Colorado
Washington
Oregon

Subregion IIIb:

Arizona
Nevada
California

Subregion IIIc:

Alaska
Hawaii

Btu Conversions

Crude Petroleum

Heat value for U.S. total crude oil for each year shown is based on the average British thermal unit (Btu) value of total output of petroleum products

(including refinery fuel and losses), adjusted to exclude natural gas liquids inputs and their implicitly derived heat values. Heat value for net imports of crude is based on the average Btu value of crude runs to stills.

Petroleum Products

The following factors were used to convert the various product volumes to Btu values:

Product:	Factor (Btu per barrel)
Gasoline	5,248,000
Kerosine	5,670,000
Distillate fuel oil	5,825,000
Residual fuel oil	6,287,000
Jet fuel (naphtha-type)	5,248,000
Liquefied gases	4,011,000

Minor adjustments were made in order to balance energy values on a State and regional basis and to meet published national totals.

SUMMARY OF DATA

Analysis of crude oil data shows a relatively stable percentage distribution of production, runs to stills, and apparent demand between subregions over the 5-year period 1960-65. Subregion IIb, the major surplus region, accounted for slightly more than two-thirds of the crude oil production and nearly one-half of the crude runs to stills in both years. The distribution and Subregion IIb shipping trends are shown in the following tabulations:

Subregion	Crude oil distribution, percent					
	Production		Runs to stills		Apparent demand	
	1960	1965	1960	1965	1960	1965
Ia	3.7	3.8	21.2	21.0	45.8	48.1
Ib	4.1	3.2	13.9	13.4	13.5	13.0
IIa	1.8	1.5	2.1	2.2	6.7	6.4
IIb	68.8	71.9	44.8	44.7	15.4	17.2
IIIa	9.7	8.1	5.0	5.6	5.7	5.5
IIIb	11.9	11.1	13.0	12.5	11.8	9.9
IIIc	Neg.	.4	Neg.	.6	.5	.9
Unaccounted for	-	-	-	-	.6	-1.0
Total	100.0	100.0	100.0	100.0	100.0	100.0

Neg.--Negligible.

Subregion destination	Net crude oil shipped from subregion IIb to other subregions, percent	
	1960	1965
Ia........	47.0	46.4
Ib........	50.9	50.6
IIa........	3.9	2.5
IIIa........	-2.8	-.7
IIIb........	1.6	1.2
IIIc........	-	-
Imports.....	-.6	-
Total..	100.0	100.0

Although total demand for products by districts remained on a fairly stable basis between 1960 and 1965, there were shifts within the various major product outputs and demands by State.

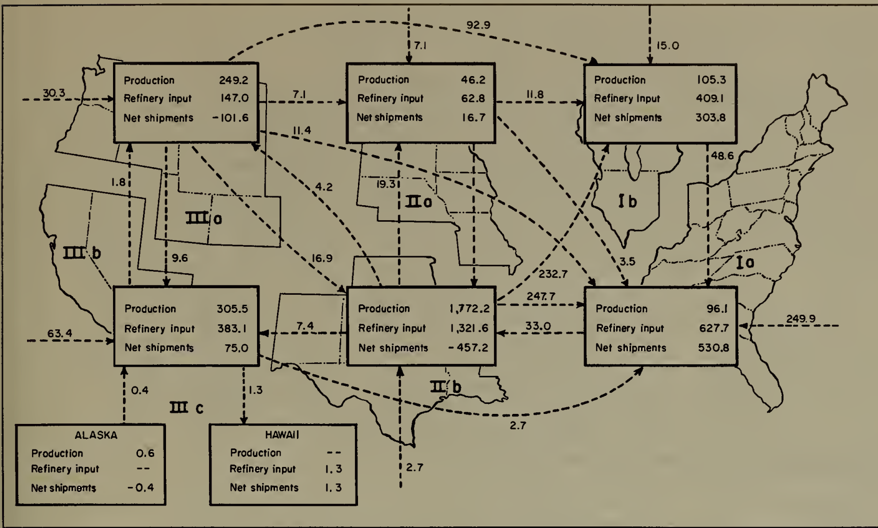


FIGURE 1. - Flow Pattern for Crude Petroleum, by Regions, 1960 (Million Barrels).

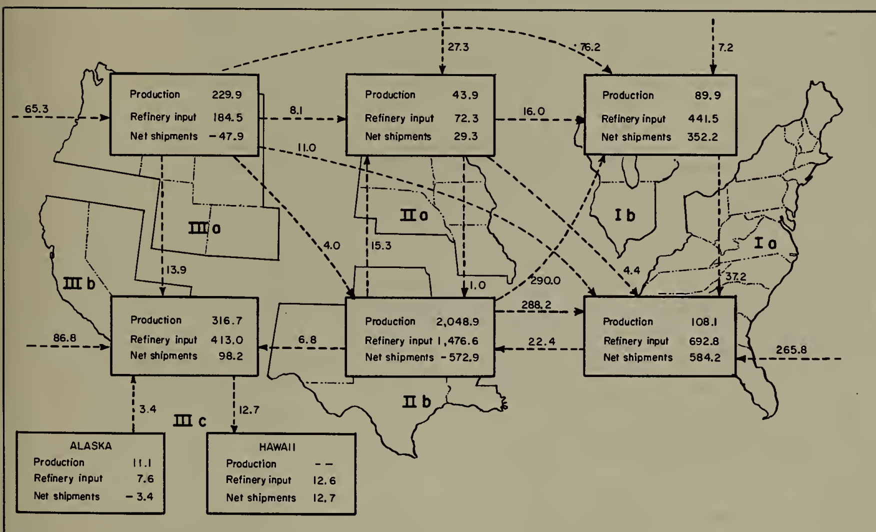


FIGURE 2. - Flow Pattern for Crude Petroleum, by Regions, 1965 (Million Barrels).

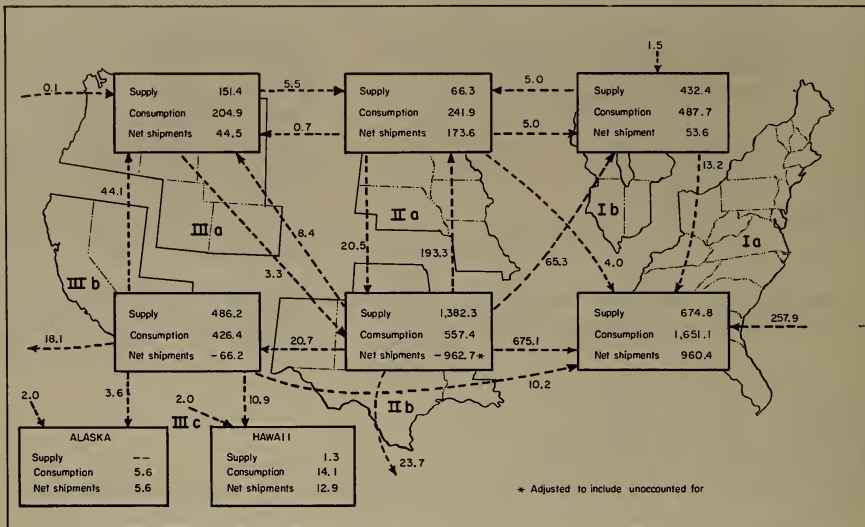


FIGURE 3. - Theoretical Flow Pattern for Petroleum Products, by Regions, 1960 (Million Barrels).

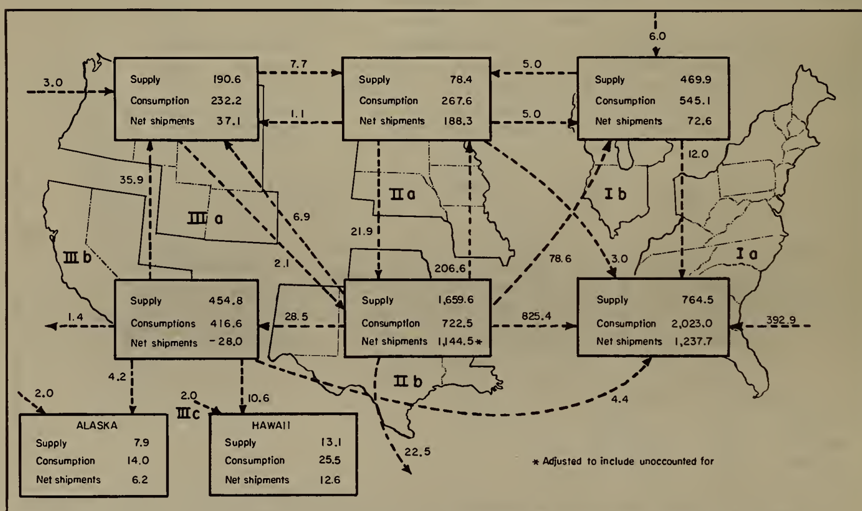


FIGURE 4. - Theoretical Flow Pattern for Petroleum Products, by Regions, 1965 (Million Barrels).

State and Region	Refined products: k change[1] ding natu- s liquids) — Trillion Btu	Transfers in of natural gas liquids — Thousand barrels	Transfers in of natural gas liquids — Trillion Btu	Net shipments[2] — Thousand barrels	Net shipments[2] — Trillion Btu	Losses, gains, and unaccounted for — Thousand barrels	Losses, gains, and unaccounted for — Trillion	Total supply available for consumption — Thousand barrels	Total supply available for consumption — Trillion Btu
United States total.	+39.5	169,542.0	679.9	+221,718.0	+1,445.5	18,200.0	-101.1	3,611,246.0	20,067.0
Region I:									
Subregion Ia:									
Maine	+.5	-	-	+27,194.0	+153.3	-	-	27,294.0	153.8
New Hampshire	+.3	-	-	+14,579.0	+81.2	-	-	14,630.0	81.5
Vermont	+.3	-	-	+7,848.0	+43.2	-	-	7,896.0	43.5
Massachusetts	+1.8	-	-	+121,347.0	+704.6	-	-	135,635.0	787.1
Rhode Island	-6.3	-	-	+25,334.0	+147.4	-	-	27,812.0	163.8
Connecticut	+.5	-	-	+62,485.0	+356.4	-	-	62,583.0	356.9
New York	+3.2	-	-	+254,981.0	+1,458.4	-	-	282,216.0	1,615.0
New Jersey	+8.2	-	-	-3,711.0	-1.2	-	-	161,460.0	937.5
Pennsylvania	-.9	-	-	-5,666.0	-18.5	-	-	200,350.0	1,165.3
Delaware	+2.6	-	-	-23,550.0	-124.6	-	-	21,729.0	130.1
Maryland	+7.7	-	-	+53,629.0	+304.9	-	-	61,368.0	353.4
District of Columbia	-	-	-	+10,295.0	+58.4	-	-	10,295.0	58.4
Virginia	+1.8	-	-	+59,234.0	+336.2	-	-	74,039.0	419.3
West Virginia	+.7	7,008.0	28.1	+15,338.0	+82.4	-	-	24,855.0	123.0
Norgh Carolina	+2.7	-	-	+68,372.0	+373.0	-	-	68,823.0	375.7
South Carolina	+1.4	-	-	+33,768.0	+184.9	-	-	36,439.0	201.5
Georgia	+1.7	-	-	+49,813.0	+266.8	-	-	51,972.0	280.8
Florida	+2.1	-	-	+99,088.0	+552.1	-	-	100,087.0	558.1
Kentucky	+1.3	3,326.0	13.3	-626.0	-5.1	-	-	35,282.0	187.1
Tennessee	+1.3	-	-	+34,285.0	+181.1	-	-	40,113.0	214.3
Alabama	+.6	-	-	+36,394.0	+194.8	-	-	40,318.0	219.0
Mississippi	-1.8	224.0	.9	+17,817.0	+89.3	-	-	25,710.0	135.0
Ohio	+2.8	-	-	+2,180.0	+10.0	-	-	140,148.0	781.4
Subtotal Ia	+32.5	10,558.0	42.3	+960,428.0	+5,429.0	-	-	1,651,054.0	9,341.5
Subregion Ib:									
Indiana	+1.7	-	-	-46,118.0	-268.2	-	-	115,448.0	657.1
Illinois	+2.7	-	-	-31,028.0	-156.4	-	-	184,949.0	1,036.8
Michigan	+5.1	-	-	+67,903.0	+367.2	-	-	119,612.0	659.7
Wisconsin	-.9	-	-	+62,820.0	+339.8	-	-	67,673.0	369.1
Subtotal Ib	+8.6	-	-	+53,577.0	+282.4	-	-	487,682.0	2,722.7
Subtotal I	+41.1	10,558.0	42.3	+1,014,005.0	+5,711.4	-	-	2,138,736.0	12,064.2
Region II:									
Subregion IIa:									
Minnesota	+.9	-	-	+42,511.0	+227.0	-	-	66,988.0	368.1
Iowa	-.3	-	-	+48,018.0	+255.3	-	-	47,941.0	255.0
Missouri	+1.4	-	-	+48,140.0	+252.4	-	-	72,254.0	388.6
North Dakota	-.3	781.0	3.1	-2,267.0	-11.8	-	-	15,613.0	83.9
South Dakota	-.3	-	-	+14,904.0	+78.7	-	-	14,845.0	78.4
Nebraska	-.3	1,039.0	4.2	+22,336.0	+117.9	-	-	24,227.0	126.9
Subtotal IIa	+1.1	1,820.0	7.3	+173,642.0	+919.5	-	-	241,868.0	1,300.9
Subregion IIb:									
Arkansas	-.8	1,445.0	5.8	-1,957.0	-18.0	-	-	29,031.0	156.8
Louisiana	-16.1	19,865.0	79.7	-193,555.0	-1,046.0	-	-	103,733.0	590.5
Oklahoma	-1.6	17,354.0	69.6	-94,209.0	-501.2	-	-	67,362.0	375.3
Texas	-5.4	93,953.0	376.8	-615,755.0	-3,342.4	-	-	269,254.0	1,385.3
New Mexico	+.5	12,963.0	52.0	-5,687.0	-13.6	-	-	21,212.0	114.6
Kansas	+.3	3,260.0	13.1	-57,143.0	-317.4	-	-	66,825.0	377.7
Subtotal IIb	-23.1	148,840.0	597.0	-968,306.0	-5,238.6	-	-	557,417.0	3,000.2
Subtotal II	-22.0	150,660.0	604.3	-794,664.0	-4,319.1	-	-	799,285.0	4,301.1
Region III:									
Subregion IIIa:									
Montana	+4.4	1,972.0	7.9	-7,424.0	-38.2	-	-	21,100.0	120.9
Idaho	-.1	-	-	+12,152.0	+65.8	-	-	12,134.0	65.7
Wyoming	-2.0	4,524.0	18.1	-20,812.0	-111.4	-	-	20,678.0	123.6
Utah	-1.1	-	-	-10,487.0	-56.5	-	-	22,325.0	128.9
Colorado	-.7	1,828.0	7.3	+13,096.0	+69.7	-	-	27,578.0	146.1
Washington	+4.8	-	-	+23,497.0	+128.1	-	-	66,777.0	377.8
Oregon	-.8	-	-	+34,448.0	+191.4	-	-	34,297.0	190.6
Subtotal IIIa	+4.5	8,324.0	33.3	+44,470.0	+248.9	-	-	204,889.0	1,153.6
Subregion IIIb:									
Arizona	-.4	-	-	+19,181.0	+101.6	-	-	19,105.0	101.2
Nevada	-.1	-	-	+7,294.0	+38.8	-	-	7,256.0	38.7
California	+42.3	-	-	-92,680.0	-527.4	-	-	400,027.0	2,335.5
Subtotal IIIb	+41.8	-	-	-66,205.0	-387.0	-	-	426,388.0	2,475.4
Subregion IIIc:									
Alaska	-.1	-	-	+5,613.0	+31.8	-	-	5,584.0	31.7
Hawaii	-.3	-	-	+12,892.0	+74.2	-	-	14,135.0	82.3
Subtotal IIIc	-.4	-	-	+18,505.0	+106.0	-	-	19,719.0	114.0
Subtotal III	+45.9	8,324.0	33.3	-3,230.0	-32.1	-	-	650,996.0	3,743.0
Foreign	-	-	-	-	-	-	-	-	-
Unaccounted for	-25.5	-	-	+5,607.0	+85.3	18,200.0	-101.1	22,229.0	-41.3

Neg.--Negligible
[1]Withdrawals fro
[2]Net foreign tra

TABLE 1. - Supply of petroleum by States and Regions

1960

Crude oil

State and Region	Production: Thousand barrels	Production: Trillion Btu	Stock change[1]: Thousand barrels	Stock change[1]: Trillion Btu	Net shipments[2]: Thousand barrels	Net shipments[2]: Trillion Btu	Losses and transfers for use as crude: Thousand barrels	Losses and transfers for use as crude: Trillion Btu	Total supply of crude oil: Thousand barrels	Total supply of crude oil: Trillion Btu
United States total.	2,574,933.0	14,664.0	+17,329.0	+98.5	+368,488.0	+2,098.6	-8,216.0	-47.2	2,952,534.0	16,813.9
Region I:										
Subregion Ia:										
Maine	-	-	-	-	-	-	-	-	-	-
New Hampshire	-	-	-	-	-	-	-	-	-	-
Vermont	-	-	-	-	-	-	-	-	-	-
Massachusetts	-	-	-	-	+13,080.0	+74.5	-	-	13,080.0	74.5
Rhode Island	-	-	-	-	+2,275.0	+13.0	-	-	2,275.0	13.0
Connecticut	-	-	-	-	-	-	-	-	-	-
New York	1,813.0	10.3	+4.0	Neg.	+23,967.0	+136.4	-5.0	.1	25,779.0	146.8
New Jersey	-	-	-	-	+147,507.0	+839.3	-61.0	.3	147,446.0	839.6
Pennsylvania	6,009.0	34.2	+306.0	+1.7	+187,871.0	+1,069.0	-182.0	-.2	194,004.0	1,104.7
Delaware	-	-	-	-	+36,072.0	+205.2	-122.0	-.5	35,950.0	204.7
Maryland	-	-	-	-	+6,617.0	+37.7	8.0	Neg.	6,625.0	37.7
District of Columbia	-	-	-	-	-	-	-	-	-	-
Virginia	2.0	Neg.	-	-	+12,644.0	+71.9	Neg.	.1	12,646.0	72.0
West Virginia	2,300.0	13.1	+10.0	Neg.	+190.0	+1.1	-7.0	Neg.	2,493.0	14.2
North Carolina	-	-	-	-	-	-	-	-	-	-
South Carolina	-	-	-	-	+3,000.0	+17.1	1.0	Neg.	3,001.0	17.1
Georgia	-	-	-	-	+1,356.0	+7.7	-	-	1,356.0	7.7
Florida	369.0	2.1	-65.0	-.4	+337.0	+1.9	-1.0	Neg.	640.0	3.6
Kentucky	21,147.0	120.4	+1,030.0	+5.9	+12,480.0	+71.0	-59.0	-.3	34,598.0	197.0
Tennessee	20.0	.1	-	-	+5,508.0	+31.3	Neg.	.1	5,528.0	31.5
Alabama	7,329.0	41.7	+129.0	+.7	-3,625.0	-20.5	-27.0	-.2	3,806.0	21.7
Mississippi	51,673.0	294.3	+14.0	+.1	-44,023.0	-250.4	-149.0	-1.2	7,515.0	42.8
Ohio	5,405.0	30.8	+66.0	+.4	+125,508.0	+714.1	-13.0	.5	130,966.0	745.8
Subtotal Ia	96,067.0	547.0	+1,494.0	+8.4	+530,764.0	+3,020.3	-617.0	-1.3	627,708.0	3,574.4
Subregion Ib:										
Indiana	12,054.0	68.6	+11.0	+.1	+142,133.0	+808.7	-175.0	-.3	154,023.0	877.1
Illinois	77,341.0	440.5	+1,438.0	+8.2	+122,448.0	+696.7	-972.0	-5.1	200,255.0	1,140.3
Michigan	15,899.0	90.5	-97.0	-.6	+34,193.0	+194.6	-227.0	-1.1	49,768.0	283.4
Wisconsin	-	-	-	-	+5,059.0	+28.8	-1.0	-	5,058.0	28.8
Subtotal Ib	105,294.0	599.6	+1,352.0	+7.7	+303,833.0	+1,728.8	-1,375.0	-6.5	409,104.0	2,329.6
Subtotal I	201,361.0	1,146.6	+2,846.0	+16.1	+834,597.0	+4,749.1	-1,992.0	-7.8	1,036,812.0	5,904.0
Region II:										
Subregion IIa:										
Minnesota	-	-	-	-	+23,440.0	+133.4	3.0	.1	23,443.0	133.5
Iowa	-	-	-	-	-	-	-	-	-	-
Missouri	75.0	.4	-	-	+22,373.0	+127.3	-2.0	.1	22,446.0	127.8
North Dakota	21,992.0	125.2	-179.0	-1.0	-5,806.0	-32.9	-19.0	-.2	15,988.0	91.1
South Dakota	281.0	1.6	+2.0	Neg.	-283.0	-1.5	Neg.	-.1	-	-
Nebraska	23,825.0	135.7	+137.0	+.8	-23,042.0	-131.0	-18.0	-.4	902.0	5.1
Subtotal IIa	46,173.0	262.9	-40.0	-.2	+16,682.0	+95.3	-36.0	-.5	62,779.0	357.5
Subregion IIb:										
Arkansas	30,117.0	171.5	+249.0	+1.4	-2,959.0	-16.7	-56.0	-.4	27,351.0	155.8
Louisiana	400,832.0	2,282.7	-2,217.0	-12.6	-154,627.0	-879.7	-951.0	-6.4	243,037.0	1,384.0
Oklahoma	192,913.0	1,098.6	+1,407.0	+8.0	-62,848.0	-357.5	-430.0	-2.8	131,042.0	746.3
Texas	927,479.0	5,282.1	+10,519.0	+59.8	-134,349.0	-764.3	-1,874.0	-11.6	801,775.0	4,566.0
New Mexico	107,380.0	611.5	+267.0	+1.5	-98,786.0	-562.0	-371.0	-2.6	8,490.0	48.4
Kansas	113,453.0	646.1	+330.0	+1.9	-3,607.0	-20.4	-236.0	-1.5	109,940.0	626.1
Subtotal IIb	1,772,174.0	10,092.5	+10,555.0	+60.0	-457,176.0	-2,600.6	-3,918.0	-25.3	1,321,635.0	7,526.6
Subtotal II	1,818,347.0	10,355.4	+10,515.0	+59.8	-440,494.0	-2,505.3	-3,954.0	-25.8	1,384,414.0	7,884.1
Region III:										
Subregion IIIa:										
Montana	30,240.0	172.2	+59.0	+.3	-5,213.0	-29.6	-82.0	-.5	25,004.0	142.4
Idaho	-	-	-	-	-	-	-	-	-	-
Wyoming	133,910.0	762.6	+87.0	+.5	-97,669.0	-555.6	-370.0	-2.7	35,958.0	204.8
Utah	37,594.0	214.1	-284.0	-1.6	-6,079.0	-34.5	-105.0	-.7	31,126.0	177.3
Colorado	47,469.0	270.3	+133.0	+.8	-35,138.0	-199.8	-115.0	-1.0	12,349.0	70.3
Washington	1.0	Neg.	-	-	+42,532.0	+242.0	-10.0	.2	42,523.0	242.2
Oregon	-	-	-	-	-	-	-	-	-	-
Subtotal IIIa	249,214.0	1,419.2	-5.0	Neg.	-101,567.0	-577.5	-682.0	-4.7	146,960.0	837.0
Subregion IIIb:										
Arizona	73.0	.4	-	-	-73.0	-.3	-	-.1	-	-
Nevada	27.0	.2	-	-	-27.0	-.2	-	-	-	-
California	305,352.0	1,739.0	+4,198.0	+23.9	+75,079.0	+427.2	-1,576.0	-8.7	383,053.0	2,181.4
Subtotal IIIb	305,452.0	1,739.6	+4,198.0	+23.9	+74,979.0	+426.7	-1,576.0	-8.8	383,053.0	2,181.4
Subregion IIIc:										
Alaska	559.0	3.2	-198.0	-1.1	-361.0	-2.1	-	-	-	-
Hawaii	-	-	-	-	+1,307.0	+7.5	-12.0	-.1	1,295.0	7.4
Subtotal IIIc	559.0	3.2	-198.0	-1.1	+946.0	+5.4	-12.0	-.1	1,295.0	7.4
Subtotal III	555,225.0	3,162.0	+3,995.0	+22.8	-25,642.0	-145.4	-2,270.0	-13.6	531,308.0	3,025.8
Foreign	-	-	-27.0	-.2	+27.0	+.2	-	-	-	-
Unaccounted for	-	-	-	-	-	-	-	-	-	-

Runs to stills

State and Region	Transfers in of natural gas liquids: Thousand barrels	Transfers in of natural gas liquids: Trillion Btu	Total refinery output: Thousand barrels	Total refinery output: Trillion Btu	Unfinished oils, net: Thousand barrels	Unfinished oils, net: Trillion Btu	Overage or loss: Thousand barrels	Overage or loss: Trillion Btu
United States total.	166,793.0	769.2	3,119,327.0	17,583.1	22,094.0	123.1	+53,282.0	+297.0
Region I:								
Subregion Ia:								
Maine	-	-	-	-	-	-	-	-
New Hampshire	-	-	-	-	-	-	-	-
Vermont	-	-	-	-	-	-	-	-
Massachusetts	-	-	13,080.0	74.5	394.0	2.2	+511.0	+4.0
Rhode Island	-	-	2,275.0	13.0	1,341.0	7.5	-57.0	+2.2
Connecticut	-	-	-	-	-	-	-	-
New York	-	-	25,779.0	146.8	525.0	2.9	+369.0	+3.7
New Jersey	310.0	1.4	147,756.0	841.0	12,165.0	67.8	+3,920.0	+21.7
Pennsylvania	1,616.0	7.4	195,620.0	1,112.1	9,282.0	51.7	+1,307.0	+20.9
Delaware	13.0	.1	35,963.0	204.8	6,656.0	37.1	+2,238.0	+10.2
Maryland	-	-	6,625.0	37.7	-122.0	-.7	-100.0	+3.8
District of Columbia	-	-	-	-	-	-	-	-
Virginia	-	-	12,646.0	72.0	996.0	5.5	+843.0	+3.8
West Virginia	-	-	2,493.0	14.2	-7.0	-	-103.0	-2.4
North Carolina	-	-	-	-	-	-	-	-
South Carolina	-	-	3,001.0	17.1	-566.0	-3.2	-11.0	+1.3
Georgia	-	-	1,356.0	7.7	495.0	2.8	+34.0	+1.8
Florida	-	-	640.0	3.6	-	-	-1.0	+.3
Kentucky	146.0	.7	34,744.0	197.7	-2,685.0	-15.0	+297.0	-5.1
Tennessee	26.0	.1	5,554.0	31.6	32.0	.2	+21.0	+.1
Alabama	14.0	.1	3,820.0	21.8	-	-	-8.0	+1.8
Mississippi	885.0	4.1	8,400.0	46.9	-14.0	-.1	-275.0	-.2
Ohio	366.0	1.7	131,332.0	747.5	2,155.0	12.0	+4,040.0	+9.1
Subtotal Ia	3,376.0	15.6	631,084.0	3,590.0	30,647.0	170.7	+13,025.0	+77.0
Subregion Ib:								
Indiana	5,221.0	24.1	159,244.0	901.2	-234.0	-1.3	+2,191.0	+23.7
Illinois	9,000.0	41.6	209,255.0	1,181.9	1,819.0	10.1	+4,287.0	-1.5
Michigan	-	-	49,768.0	283.4	847.0	4.7	+201.0	-.7
Wisconsin	-	-	5,058.0	28.8	-	-	-14.0	+1.4
Subtotal Ib	14,221.0	65.7	423,325.0	2,395.3	2,432.0	13.5	+6,665.0	+22.9
Subtotal I	17,597.0	81.3	1,054,409.0	5,985.3	33,079.0	184.2	+19,690.0	+99.9
Region II:								
Subregion IIa:								
Minnesota	85.0	.4	23,528.0	133.9	106.0	.6	+688.0	+5.7
Iowa	-	-	-	-	-	-	-	-
Missouri	243.0	1.1	22,689.0	128.9	217.0	1.2	+966.0	+4.7
North Dakota	682.0	3.1	16,670.0	94.2	-7.0	-	+495.0	-1.3
South Dakota	-	-	-	-	-	-	-	-
Nebraska	52.0	.2	954.0	5.3	-	-	-9.0	-.2
Subtotal IIa	1,062.0	4.8	63,841.0	362.3	316.0	1.8	+2,140.0	+8.9
Subregion IIb:								
Arkansas	995.0	4.6	28,346.0	160.4	570.0	3.2	+780.0	+6.2
Louisiana	23,648.0	109.1	266,685.0	1,493.1	3,973.0	22.1	+9,895.0	+57.7
Oklahoma	10,554.0	48.8	141,596.0	795.1	758.0	4.2	+2,153.0	+9.2
Texas	983.0	4.5	802,758.0	4,570.5	-23,413.0	-130.4	+13,777.0	-83.8
New Mexico	5,573.0	25.7	14,063.0	74.1	-4.0	-	-244.0	+1.6
Kansas	11,146.0	51.5	121,086.0	677.6	341.0	1.9	-776.0	+2.2
Subtotal IIb	[illegible]899.0	244.2	1,374,534.0	7,770.8	-17,775.0	-99.0	+25,585.0	-6.9
Subtotal II	[illegible],961.0	249.0	1,438,375.0	8,133.1	-17,459.0	-97.2	+27,725.0	+2.0
Region III:								
Subregion IIIa:								
Montana	444.0	2.0	25,448.0	144.4	-	-	+364.0	+2.4
Idaho	-	-	-	-	-	-	-	-
Wyoming	1,225.0	5.6	37,183.0	210.4	-14.0	-.1	+122.0	+8.6
Utah	1,438.0	6.6	32,564.0	183.9	-73.0	-.4	+517.0	+3.0
Colorado	131.0	.6	12,480.0	70.9	-77.0	-.4	+349.0	-.7
Washington	-	-	42,523.0	242.2	-	-	Neg.	+2.7
Oregon	-	-	-	-	-	-	-	-
Subtotal IIIa	3,238.0	14.8	150,198.0	851.8	-164.0	-.9	+1,352.0	+16.0
Subregion IIIb:								
Arizona	-	-	-	-	-	-	-	-
Nevada	-	-	-	-	-	-	-	-
California	91,997.0	424.1	475,050.0	2,605.5	6,638.0	37.0	+4,515.0	+178.1
Subtotal IIIb	91,997.0	424.1	475,050.0	2,605.5	6,638.0	37.0	+4,515.0	+178.1
Subregion IIIc:								
Alaska	-	-	-	-	-	-	-	-
Hawaii	-	-	1,295.0	7.4	-	-	-	+1.0
Subtotal IIIc	-	-	1,295.0	7.4	-	-	-	+1.0
Subtotal III	95,235.0	438.9	626,543.0	3,464.7	6,474.0	36.1	+5,867.0	+195.1
Foreign	-	-	-	-	-	-	-	-
Unaccounted for	-	-	-	-	-	-	-	-

Refined products

State and Region	Total supply of refined products: Thousand barrels	Total supply of refined products: Trillion Btu	Stock change[1] (including natural gas liquids): Thousand barrels	Stock change[1] (including natural gas liquids): Trillion Btu	Transfers in of natural gas liquids: Thousand barrels	Transfers in of natural gas liquids: Trillion Btu	Net shipments[2]: Thousand barrels	Net shipments[2]: Trillion Btu	Losses, gains, and unaccounted for: Thousand barrels	Losses, gains, and unaccounted for: Trillion	Total supply available for consumption: Thousand barrels	Total supply available for consumption: Trillion Btu
United States total.	3,194,703.0	18,003.2	+7,083.0	+39.5	169,542.0	679.9	+221,718.0	+1,445.5	18,200.0	-101.1	3,611,246.0	20,067.0
Region I:												
Subregion Ia:												
Maine	-	-	+100.0	+.5	-	-	+27,194.0	+153.3	-	-	27,294.0	153.8
New Hampshire	-	-	+51.0	+.3	-	-	+14,579.0	+81.2	-	-	14,630.0	81.5
Vermont	-	-	+48.0	+.3	-	-	+7,848.0	+43.2	-	-	7,896.0	43.5
Massachusetts	13,985.0	80.7	+303.0	+1.8	-	-	+121,347.0	+704.6	-	-	135,635.0	787.1
Rhode Island	3,559.0	22.7	-1,081.0	-6.3	-	-	+25,334.0	+147.4	-	-	27,812.0	163.8
Connecticut	-	-	+98.0	+.5	-	-	+62,485.0	+356.4	-	-	62,583.0	356.9
New York	26,673.0	153.4	+562.0	+3.2	-	-	+254,981.0	+1,458.4	-	-	282,216.0	1,615.0
New Jersey	163,841.0	930.5	+1,330.0	+8.2	-	-	-3,711.0	-1.2	-	-	161,460.0	937.5
Pennsylvania	206,209.0	1,184.7	-193.0	-.9	-	-	-5,666.0	-18.5	-	-	200,350.0	1,165.3
Delaware	44,857.0	252.1	+422.0	+2.6	-	-	-23,550.0	-124.6	-	-	21,729.0	130.1
Maryland	6,403.0	40.8	+1,336.0	+7.7	-	-	+53,629.0	+304.9	-	-	61,368.0	353.4
District of Columbia	-	-	-	-	-	-	+10,295.0	+58.4	-	-	10,295.0	58.4
Virginia	14,485.0	81.3	+320.0	+1.8	-	-	+59,234.0	+336.2	-	-	74,039.0	419.3
West Virginia	2,383.0	11.8	+126.0	+.7	7,008.0	28.1	+15,338.0	+82.4	-	-	24,855.0	123.0
North Carolina	-	-	+451.0	+2.7	-	-	+68,372.0	+373.0	-	-	68,823.0	375.7
South Carolina	2,424.0	15.2	+247.0	+1.4	-	-	+33,768.0	+184.9	-	-	36,439.0	201.5
Georgia	1,885.0	12.3	+274.0	+1.7	-	-	+49,813.0	+266.8	-	-	51,972.0	280.8
Florida	639.0	3.9	+360.0	+2.1	-	-	+99,088.0	+552.1	-	-	100,087.0	558.1
Kentucky	32,356.0	177.6	+226.0	+1.3	3,326.0	13.3	-626.0	-5.1	-	-	35,282.0	187.1
Tennessee	5,607.0	31.9	+221.0	+1.3	-	-	+34,285.0	+181.1	-	-	40,113.0	214.3
Alabama	3,812.0	23.6	+112.0	+.6	-	-	+36,394.0	+194.8	-	-	40,318.0	219.0
Mississippi	8,111.0	46.6	-442.0	-1.8	224.0	.9	+17,817.0	+89.3	-	-	25,710.0	135.0
Ohio	137,527.0	768.6	+441.0	+2.8	-	-	+2,180.0	+10.0	-	-	140,148.0	781.4
Subtotal Ia	674,756.0	3,837.7	+5,312.0	+32.5	10,558.0	42.3	+960,428.0	+5,429.0	-	-	1,651,054.0	9,341.5
Subregion Ib:												
Indiana	161,201.0	923.6	+365.0	+1.7	-	-	-46,118.0	-268.2	-	-	115,448.0	657.1
Illinois	215,361.0	1,190.5	+616.0	+2.7	-	-	-31,028.0	-156.4	-	-	184,949.0	1,036.8
Michigan	50,816.0	287.4	+893.0	+5.1	-	-	+67,903.0	+367.2	-	-	119,612.0	659.7
Wisconsin	5,044.0	30.2	-191.0	-.9	-	-	+62,820.0	+339.8	-	-	67,673.0	369.1
Subtotal Ib	432,422.0	2,431.7	+1,683.0	+8.6	-	-	+53,577.0	+282.4	-	-	487,682.0	2,722.7
Subtotal I	1,107,178.0	6,269.4	+6,995.0	+41.1	10,558.0	42.3	+1,014,005.0	+5,711.4	-	-	2,138,736.0	12,064.2
Region II:												
Subregion IIa:												
Minnesota	24,322.0	140.2	+155.0	+.9	-	-	+42,511.0	+227.0	-	-	66,988.0	368.1
Iowa	-	-	-77.0	-.3	-	-	+48,018.0	+255.3	-	-	47,941.0	255.0
Missouri	23,872.0	134.8	+242.0	+1.4	-	-	+48,140.0	+252.4	-	-	72,254.0	388.6
North Dakota	17,158.0	92.9	-59.0	-.3	781.0	3.1	-2,267.0	-11.8	-	-	15,613.0	83.9
South Dakota	-	-	-59.0	-.3	-	-	+14,904.0	+78.7	-	-	14,845.0	78.4
Nebraska	945.0	5.1	-93.0	-.3	1,039.0	4.2	+22,336.0	+117.9	-	-	24,227.0	126.9
Subtotal IIa	66,297.0	373.0	+109.0	+1.1	1,820.0	7.3	+173,642.0	+919.5	-	-	241,868.0	1,300.9
Subregion IIb:												
Arkansas	29,696.0	169.8	-153.0	-.8	1,445.0	5.8	-1,957.0	-18.0	-	-	29,031.0	156.8
Louisiana	280,553.0	1,572.9	-3,130.0	-16.1	19,865.0	79.7	-193,555.0	-1,046.0	-	-	103,733.0	590.5
Oklahoma	144,507.0	808.5	-290.0	-1.6	17,354.0	69.6	-94,209.0	-501.2	-	-	67,362.0	375.3
Texas	793,122.0	4,356.3	-2,066.0	-5.4	93,953.0	376.8	-615,755.0	-3,342.4	-	-	269,254.0	1,385.3
New Mexico	[illegible]	75.7	+121.0	+.5	12,963.0	52.0	-5,687.0	-13.6	-	-	21,212.0	114.6
Kansas	120,651.0	681.7	+57.0	+.3	3,260.0	13.1	-57,143.0	-317.4	-	-	66,825.0	377.7
Subtotal IIb	1,382,344.0	7,664.9	-5,461.0	-23.1	148,840.0	597.0	-968,306.0	-5,238.6	-	-	557,417.0	3,000.2
Subtotal II	1,448,641.0	8,037.9	-5,352.0	-22.0	150,660.0	604.3	-794,664.0	-4,319.1	-	-	799,285.0	4,301.1
Region III:												
Subregion IIIa:												
Montana	25,812.0	146.8	+740.0	+4.4	1,972.0	7.9	-7,424.0	-38.2	-	-	21,100.0	120.9
Idaho	-	-	-18.0	-.1	-	-	+12,152.0	+65.8	-	-	12,134.0	65.7
Wyoming	37,291.0	218.9	-325.0	-2.0	4,524.0	18.1	-20,812.0	-111.4	-	-	20,678.0	123.6
Utah	33,008.0	186.5	-196.0	-1.1	-	-	-10,487.0	-56.5	-	-	22,325.0	128.9
Colorado	12,752.0	69.8	-98.0	-.7	1,828.0	7.3	+13,096.0	+69.7	-	-	27,578.0	146.1
Washington	42,523.0	244.9	+757.0	+4.8	-	-	+23,497.0	+128.1	-	-	66,777.0	377.8
Oregon	-	-	-151.0	-.8	-	-	+34,448.0	+191.4	-	-	34,297.0	190.6
Subtotal IIIa	151,386.0	866.9	+709.0	+4.5	8,324.0	33.3	+44,470.0	+248.9	-	-	204,889.0	1,153.6
Subregion IIIb:												
Arizona	-	-	-76.0	-.4	-	-	+19,181.0	+101.6	-	-	19,105.0	101.2
Nevada	-	-	-38.0	-.1	-	-	+7,294.0	+38.8	-	-	7,256.0	38.7
California	486,203.0	2,820.6	+6,504.0	+42.3	-	-	-92,680.0	-527.4	-	-	400,027.0	2,335.5
Subtotal IIIb	486,203.0	2,820.6	+6,390.0	+41.8	-	-	-66,205.0	-387.0	-	-	426,388.0	2,475.4
Subregion IIIc:												
Alaska	-	-	-29.0	-.1	-	-	+5,613.0	+31.8	-	-	5,584.0	31.7
Hawaii	1,295.0	8.4	-52.0	-.3	-	-	+12,892.0	+74.2	-	-	14,135.0	82.3
Subtotal IIIc	1,295.0	8.4	-81.0	-.4	-	-	+18,505.0	+106.0	-	-	19,719.0	114.0
Subtotal III	638,884.0	3,695.9	+7,018.0	+45.9	8,324.0	33.3	-3,230.0	-32.1	-	-	650,996.0	3,743.0
Foreign	-	-	-	-	-	-	-	-	-	-	-	-
Unaccounted for	-	-	-1,578.0	-25.5	-	-	+5,607.0	+85.3	18,200.0	-101.1	22,229.0	-41.3

Neg.--Negligible
[1]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.
[2]Net foreign trade, at the national level, is equal to net shipments, and is not additive to horizontal totals.

TAI

nsfers tural liquid housanc arrels
6,793.(
-
-
-
-
-
-
-
310
1,616
13
-
-
-
-
-
-
-
-
14
8
3
3,3
5,2
9,0
14,
17,

State and Region	ck change[1] luding natu- gas liquids)		Refined products: Transfers in of natural gas liquids		Net shipments[2]		Losses, gains, and unaccounted for		Total supply available for consumption	
	and ls	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States tota	9.0	-158.8	215,692.0	833.8	+381,950.0	+2,347.2	-27,400.0	-151.3	4,202,424.0	22,983.2
Region I:										
Subregion Ia:										
Maine	9.0	+0.7	-	-	+31,238.0	+176.4	-	-	31,377.0	177.1
New Hampshire.	3.0	+.3	-	-	+16,751.0	+93.2	-	-	16,814.0	93.5
Vermont......	4.0	+.3	-	-	+10,180.0	+56.6	-	-	10,234.0	56.9
Massachusetts.	7.0	+4.9	-	-	+157,029.0	+912.9	-	-	160,061.0	929.8
Rhode Island.	2.0	+5.0	-	-	+19,656.0	+113.0	-	-	24,905.0	143.7
Connecticut..	5.0	+.5	-	-	+66,795.0	+380.1	-	-	66,891.0	380.6
New York.....	1.0	+9.3	-	-	+334,276.0	+1,923.7	-	-	365,262.0	2,096.2
New Jersey...	4.0	+9.8	-	-	+9,006.0	+76.2	-	-	194,413.0	1,123.7
Pennsylvania.	1.0	+1.2	-	-	+14,224.0	+110.5	-	-	226,717.0	1,299.0
Delaware.....	0.0	-.6	-	-	-23,252.0	-120.0	-	-	19,795.0	126.2
Maryland.....	2.0	+7.8	-	-	+64,317.0	+362.8	-	-	69,218.0	389.9
District of Columbia....	7.0	Neg.	-	-	+15,597.0	+90.8	-	-	15,604.0	90.8
Virginia.....	5.0	+1.8	-	-	+72,407.0	+407.2	-	-	87,372.0	491.5
West Virginia	9.0	+.7	4,756.0	18.4	+21,139.0	+108.0	-	-	28,231.0	139.4
North Carolin	6.0	+3.5	-	-	+82,969.0	+451.1	-	-	83,625.0	454.6
South Carolin	7.0	+1.9	-	-	+35,919.0	+194.5	-	-	36,286.0	196.4
Georgia......	8.0	+2.9	-	-	+64,591.0	+348.0	-	-	67,749.0	365.3
Florida......	3.0	+2.5	959.0	3.7	+138,902.0	+784.0	-	-	141,284.0	795.3
Kentucky.....	9.0	+2.3	3,064.0	11.8	+6,847.0	+30.5	-	-	44,755.0	236.7
Tennessee....	9.0	+1.6	-	-	+39,185.0	+207.2	-	-	50,075.0	267.8
Alabama......	0.0	+1.1	-	-	+39,454.0	+207.9	-	-	43,784.0	231.8
Mississippi..	8.0	+1.6	914.0	3.5	+18,866.0	+95.0	-	-	73,452.0	396.5
Ohio.........	7.0	-.2	-	-	+1,572.0	+6.6	-	-	165,056.0	917.5
Subtotal Ia	4.0	+58.9	9,693.0	37.4	+1,237,668.0	+7,016.2	-	-	2,022,960.0	11,400.2
Subregion Ib:										
Indiana......	8.0	+2.0	-	-	-41,078.0	-238.8	-	-	134,542.0	731.0
Illinois.....	9.0	+2.0	-	-	-31,306.0	-166.9	-	-	206,170.0	1,147.8
Michigan.....	9.0	+8.1	-	-	+80,652.0	+436.9	-	-	132,439.0	722.4
Wisconsin....	1.0	-.5	-	-	+64,377.0	+346.2	-	-	71,947.0	388.6
Subtotal Ib	5.0	+11.6	-	-	+72,645.0	+377.4	-	-	545,098.0	2,989.8
Subtotal	9.0	+70.5	9,693.0	37.4	+1,310,313.0	+7,393.6	-	-	2,568,058.0	14,390.0
Region II:										
Subregion IIa:										
Minnesota....	7.0	-.4	-	-	+40,359.0	+213.1	-	-	73,579.0	400.2
Iowa.........	7.0	-.1	45.0	.2	+51,511.0	+270.5	-	-	51,573.0	270.6
Missouri.....	5.0	-.4	-	-	+53,379.0	+277.9	-	-	79,910.0	426.0
North Dakota.	8.0	-.1	771.0	3.0	-678.0	-2.5	-	-	17,740.0	95.6
South Dakota.	8.0	-.5	-	-	+18,820.0	+97.0	-	-	18,732.0	96.5
Nebraska.....	9.0	Neg.	183.0	.7	+24,918.0	+129.5	-	-	26,068.0	135.6
Subtotal II	4.0	-1.5	999.0	3.9	+188,309.0	+985.5	-	-	267,602.0	1,424.5
Subregion IIb:										
Arkansas.....	0.0	+.2	1,277.0	4.9	+1,465.0	-.8	-	-	34,489.0	180.8
Louisiana....	6.0	-15.1	34,347.0	132.8	-269,099.0	-1,457.6	-	-	89,525.0	456.7
Oklahoma.....	2.0	+3.3	18,564.0	71.8	-101,198.0	-535.6	-	-	73,612.0	397.3
Texas........	1.0	+.3	118,715.0	459.9	-683,058.0	-3,699.1	-	-	447,692.0	2,287.0
New Mexico...	1.0	Neg.	16,229.0	61.7	-8,579.0	-23.9	-	-	20,378.0	107.6
Kansas.......	3.0	+.7	9,507.0	36.8	-73,475.0	-389.9	-	-	56,758.0	314.2
Subtotal II	1.0	-10.6	198,639.0	767.9	-1,133,944.0	-6,106.9	-	-	722,454.0	3,743.6
Subtotal	5.0	-12.1	199,638.0	771.8	-945,635.0	-5,121.4	-	-	990,056.0	5,168.1
Region III:										
Subregion IIIa										
Montana......	2.0	Neg.	1,262.0	4.9	-11,881.0	-64.9	-	-	22,973.0	123.0
Idaho........	7.0	-.2	-	-	+14,172.0	+77.2	-	-	14,155.0	77.0
Wyoming......	3.0	-1.3	3,175.0	12.3	-23,576.0	-125.5	-	-	23,104.0	128.0
Utah.........	6.0	-1.0	-	-	-11,483.0	-62.9	-	-	24,652.0	136.2
Colorado.....	7.0	-.2	1,924.0	7.4	+18,460.0	+98.9	-	-	33,496.0	179.5
Washington...	6.0	-8.3	-	-	+13,558.0	+75.9	-	-	73,639.0	410.3
Oregon.......	5.0	-.8	-	-	+37,816.0	+209.5	-	-	40,215.0	222.8
Subtotal I	2.0	-11.8	6,361.0	24.6	+37,066.0	+208.2	-	-	232,234.0	1,276.8
Subregion IIIb										
Arizona......	1.0	Neg.	-	-	+22,951.0	+121.7	-	-	22,952.0	121.7
Nevada.......	1.0	Neg.	-	-	+10,336.0	+55.4	-	-	10,335.0	55.4
California...	1.0	-63.7	-	-	-61,274.0	-354.1	-	-	383,266.0	2,102.9
Subtotal I	1.0	-63.7	-	-	-27,987.0	-177.0	-	-	416,553.0	2,280.0
Subregion IIIc										
Alaska.......	22.0	-.7	-	-	+6,216.0	+34.6	-	-	13,958.0	77.8
Hawaii.......	42.0	-1.5	-	-	+12,609.0	+74.5	-	-	25,473.0	146.6
Subtotal I	64.0	-2.2	-	-	+18,825.0	+109.1	-	-	39,431.0	224.4
Subtotal	27.0	-77.7	6,361.0	24.6	+27,904.0	+140.3	-	-	688,218.0	3,781.2
Foreign.........	-	-	-	-	-	-	-	-	-	-
Unaccounted for.	76.0	-139.5	-	-	-10,632.0	-65.3	-27,400.0	-151.3	-43,908.0	-356.1

Neg.--Negligible

[1]Withdrawals fro

[2]Net foreign tra

TABLE 3. - Supply of petroleum by States and Regions

1965

State and Region	Crude oil: Production, Thousand barrels	Crude oil: Production, Trillion Btu	Crude oil: Stock change[1], Thousand barrels	Crude oil: Stock change[1], Trillion Btu	Crude oil: Net shipments[2], Thousand barrels	Crude oil: Net shipments[2], Trillion Btu	Crude oil: Losses and transfers for use as crude, Thousand barrels	Crude oil: Losses and transfers for use as crude, Trillion Btu	Runs to stills: Total supply of crude oil, Thousand barrels	Runs to stills: Total supply of crude oil, Trillion Btu	Runs to stills: Transfers in of natural gas liquids, Thousand barrels	Runs to stills: Transfers in of natural gas liquids, Trillion Btu	Runs to stills: Total refinery output, Thousand barrels	Runs to stills: Total refinery output, Trillion Btu	Unfinished oils, net, Thousand barrels	Unfinished oils, net, Trillion Btu	Overage or loss, Thousand barrels	Overage or loss, Trillion Btu	Refined products: Total supply of refined products, Thousand barrels	Refined products: Total supply of refined products, Trillion Btu	Refined products: Stock change[1] (including natural gas liquids), Thousand barrels	Refined products: Stock change[1] (including natural gas liquids), Trillion Btu	Refined products: Transfers in of natural gas liquids, Thousand barrels	Refined products: Transfers in of natural gas liquids, Trillion Btu	Refined products: Net shipments[2], Thousand barrels	Refined products: Net shipments[2], Trillion Btu	Losses, gains, and unaccounted for, Thousand barrels	Losses, gains, and unaccounted for, Trillion Btu	Total supply available for consumption, Thousand barrels	Total supply available for consumption, Trillion Btu
United States total.	2,848,514.0	15,900.4	+9,768.0	+54.7	+450,944.0	+2,516.9	-8,383.0	-46.9	3,300,843.0	18,425.1	225,676.0	1,042.7	3,526,519.0	19,467.8	32,111.0	201.8	+80,241.0	+442.7	3,638,871.0	20,112.3	-6,689.0	-158.8	215,692.0	833.8	+381,950.0	+2,347.2	-27,400.0	-151.3	4,202,424.0	22,983.2
Region I:																														
Subregion Ia:																														
Maine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+139.0	+0.7	-	-	+31,238.0	+176.4	-	-	31,377.0	177.1
New Hampshire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+63.0	+.3	-	-	+16,751.0	+93.2	-	-	16,814.0	93.5
Vermont	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+54.0	+.3	-	-	+10,180.0	+56.6	-	-	10,234.0	56.9
Massachusetts	-	-	-	-	+2,241.0	+12.5	-3.0	Neg.	2,238.0	12.5	-	-	2,238.0	12.5	-77.0	-.5	+4.0	Neg.	2,165.0	12.0	+867.0	+4.9	-	-	+157,029.0	+912.9	-	-	160,061.0	929.8
Rhode Island	-	-	-	-	+2,614.0	+14.6	-3.0	Neg.	2,611.0	14.6	-	-	2,611.0	14.6	1,775.0	11.1	-9.0	Neg.	4,377.0	25.7	+872.0	+5.0	-	-	+19,656.0	+113.0	-	-	24,905.0	143.7
Connecticut	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+96.0	+.5	-	-	+66,795.0	+380.1	-	-	66,891.0	380.6
New York	1,632.0	9.1	-	-	+25,968.0	+144.9	-	-	27,600.0	154.0	-	-	27,600.0	154.0	1,002.0	6.3	+523.0	+2.9	29,125.0	163.2	+1,861.0	+9.3	-	-	+334,276.0	+1,923.7	-	-	365,262.0	2,096.2
New Jersey	-	-	-	-	+158,951.0	+887.4	-13.0	-.1	158,938.0	887.3	1,169.0	5.4	160,107.0	892.7	19,537.0	122.9	+4,009.0	+22.1	183,653.0	1,037.7	+1,754.0	+9.8	-	-	+9,006.0	+76.2	-	-	194,413.0	1,123.7
Pennsylvania	[illegible],922.0	27.5	+334.0	+1.9	+187,249.0	+1,045.4	-149.0	-.8	192,356.0	1,074.0	4,823.0	22.3	197,179.0	1,096.3	9,991.0	62.8	+5,112.0	+28.2	212,282.0	1,187.3	+211.0	+1.2	-	-	+14,224.0	+110.5	-	-	226,717.0	1,299.0
Delaware	-	-	-	-	+32,494.0	+181.6	-50.0	-.3	32,444.0	181.3	-	-	32,444.0	181.3	8,306.0	52.2	+2,407.0	+13.3	43,157.0	246.8	-110.0	-.6	-	-	-23,252.0	-120.0	-	-	19,795.0	126.2
Maryland	-	-	-	-	+4,170.0	+23.3	32.0	.2	4,202.0	23.5	-	-	4,202.0	23.5	-643.0	-4.0	-40.0	-0.2	3,519.0	19.3	+1,382.0	+7.8	-	-	+64,317.0	+362.8	-	-	69,218.0	389.9
District of Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+7.0	Neg.	-	-	+15,597.0	+90.8	-	-	15,604.0	90.8
Virginia	4.0	Neg.	-	-	+11,793.0	+65.8	-	-	11,797.0	65.8	-	-	11,797.0	65.8	1,555.0	9.8	+1,247.0	+6.9	14,599.0	82.5	+366.0	+1.8	-	-	+72,407.0	+407.2	-	-	87,372.0	491.5
West Virginia	3,530.0	19.7	+329.0	+1.8	-1,587.0	-8.9	-	-	2,272.0	12.6	-	-	2,272.0	12.6	-15.0	-.1	-40.0	-.2	2,217.0	12.3	+119.0	+.7	4,756.0	18.4	+21,139.0	+108.0	-	-	28,231.0	139.4
North Carolina	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+656.0	+3.5	-	-	+82,969.0	+451.1	-	-	83,625.0	454.6
South Carolina	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+367.0	+1.9	-	-	+35,919.0	+194.5	-	-	36,286.0	196.4
Georgia	-	-	-	-	+2,604.0	+14.5	-	-	2,604.0	14.5	-	-	2,604.0	14.5	-20.0	-.1	+6.0	Neg.	2,590.0	14.4	+568.0	+2.9	-	-	+64,591.0	+348.0	-	-	67,749.0	365.3
Florida	1,464.0	8.2	-228.0	-1.3	-317.0	-1.8	-	-	919.0	5.1	-	-	919.0	5.1	-	-	-9.0	Neg.	910.0	5.1	+513.0	+2.5	959.0	3.7	+138,902.0	+784.0	-	-	141,284.0	795.3
Kentucky	19,386.0	108.2	+290.0	+1.6	+13,885.0	+77.6	-43.0	-.2	33,518.0	187.2	70.0	.3	33,588.0	187.5	377.0	2.4	+400.0	+2.2	34,365.0	192.1	+479.0	+2.3	3,064.0	11.8	+6,847.0	+30.5	-	-	44,755.0	236.7
Tennessee	11.0	.1	-	-	+10,592.0	+59.1	-18.0	-.1	10,585.0	59.1	127.0	.6	10,712.0	59.7	-	-	-131.0	-.7	10,581.0	59.0	+309.0	+1.6	-	-	+39,185.0	+207.2	-	-	50,075.0	267.8
Alabama	8,064.0	45.0	+112.0	+.6	-4,099.0	-22.9	14.0	.1	4,091.0	22.8	-	-	4,091.0	22.8	-	-	+9.0	Neg.	4,100.0	22.8	+230.0	+1.1	-	-	+39,454.0	+207.9	-	-	43,784.0	231.8
Mississippi	56,183.0	313.7	+175.0	+1.0	-4,264.0	-23.8	-114.0	-.6	51,980.0	290.3	1,086.0	5.0	53,066.0	295.3	4.0	Neg.	+204.0	+1.1	53,274.0	296.4	+398.0	+1.6	914.0	3.5	+18,866.0	+95.0	-	-	73,452.0	396.5
Ohio	12,908.0	72.1	+71.0	+.4	+141,874.0	+792.2	-239.0	-1.3	154,614.0	863.4	2,586.0	11.9	157,200.0	875.3	690.0	4.3	+5,701.0	+31.5	163,591.0	911.1	-107.0	-.2	-	-	+1,572.0	+6.6	-	-	165,056.0	917.5
Subtotal Ia	108,104.0	603.6	+1,083.0	+6.0	+584,168.0	+3,261.5	-586.0	-3.1	692,769.0	3,868.0	9,861.0	45.5	702,630.0	3,913.5	42,482.0	267.1	+19,393.0	+107.1	764,505.0	4,287.7	+11,094.0	+58.9	9,693.0	37.4	+1,237,668.0	+7,016.2	-	-	2,022,960.0	11,400.2
Subregion Ib:																														
Indiana	11,481.0	64.1	+53.0	+.3	+147,955.0	+826.1	-247.0	-1.4	159,242.0	889.1	10,580.0	48.9	169,822.0	938.0	1,114.0	7.0	+4,136.0	+22.8	175,072.0	967.8	+548.0	+2.0	-	-	-41,078.0	-238.8	-	-	134,542.0	731.0
Illinois	63,708.0	355.7	-136.0	-.8	+159,318.0	+889.5	-337.0	-1.9	222,553.0	1,242.5	9,432.0	43.6	231,985.0	1,286.1	-1,563.0	-9.8	+6,585.0	+36.4	237,007.0	1,312.7	+469.0	+2.0	-	-	-31,306.0	-166.9	-	-	206,170.0	1,147.8
Michigan	14,728.0	82.2	+262.0	+1.5	+37,357.0	+208.8	-155.0	-.9	52,192.0	291.6	629.0	2.9	52,821.0	294.5	-3,085.0	-19.4	+422.0	+2.3	50,158.0	277.4	+1,629.0	+8.1	-	-	+80,652.0	+436.9	-	-	132,439.0	722.4
Wisconsin	-	-	-	-	+7,616.0	+42.7	-109.0	-.6	7,507.0	42.1	182.0	.8	7,689.0	42.9	23.0	.1	-21.0	-.1	7,691.0	42.9	-121.0	-.5	-	-	+64,377.0	+346.2	-	-	71,947.0	388.6
Subtotal Ib	89,917.0	502.0	+179.0	+1.0	+352,246.0	+1,967.1	-848.0	-4.8	441,494.0	2,465.3	20,823.0	96.2	462,317.0	2,561.5	-3,511.0	-22.1	+11,122.0	+61.4	469,928.0	2,600.8	+2,525.0	+11.6	-	-	+72,645.0	+377.4	-	-	545,098.0	2,989.8
Subtotal I	198,021.0	1,105.6	+1,262.0	+7.0	+936,414.0	+5,228.6	-1,434.0	-7.9	1,134,263.0	6,333.3	30,684.0	141.7	1,164,947.0	6,475.0	38,971.0	245.0	+30,515.0	+168.5	1,234,433.0	6,888.5	+13,619.0	+70.5	9,693.0	37.4	+1,310,313.0	+7,393.6	-	-	2,568,058.0	14,390.0
Region II:																														
Subregion IIa:																														
Minnesota	-	-	-	-	+31,678.0	+179.9	-478.0	-2.7	31,200.0	177.2	1,068.0	4.9	32,268.0	182.1	-2.0	Neg.	+971.0	+5.4	33,237.0	187.5	-17.0	-.4	-	-	+40,359.0	+213.1	-	-	73,579.0	400.2
Iowa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+17.0	-.1	45.0	.2	+51,511.0	+270.5	-	-	51,573.0	270.6
Missouri	73.0	.4	-	-	+22,908.0	+128.2	-	-	22,981.0	128.6	1,283.0	5.9	24,264.0	134.5	1,608.0	10.1	+704.0	+3.9	26,576.0	148.5	-45.0	-.4	-	-	+53,379.0	+277.9	-	-	79,910.0	426.0
North Dakota	26,350.0	147.1	-185.0	-1.0	-8,831.0	-52.4	-205.0	-1.2	17,129.0	92.5	-	-	17,129.0	92.5	-49.0	-.3	+549.0	+3.0	17,629.0	95.2	+18.0	-.1	771.0	3.0	-678.0	-2.5	-	-	17,740.0	95.6
South Dakota	219.0	1.2	-	-	-219.0	-1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-88.0	-.5	-	-	+18,820.0	+97.0	-	-	18,732.0	96.5
Nebraska	17,216.0	96.1	+28.0	+.2	-16,286.0	-90.9	-	-	958.0	5.4	-	-	958.0	5.4	-	-	+18.0	Neg.	976.0	5.4	-9.0	Neg.	183.0	.7	+24,918.0	+129.5	-	-	26,068.0	135.6
Subtotal IIa	43,858.0	244.8	-157.0	-.8	+29,250.0	+163.6	-683.0	-3.9	72,268.0	403.7	2,351.0	10.8	74,619.0	414.5	1,557.0	9.8	+2,242.0	+12.3	78,418.0	436.6	-124.0	-1.5	999.0	3.9	+188,309.0	+985.5	-	-	267,602.0	1,424.5
Subregion IIb:																														
Arkansas	25,930.0	144.7	+235.0	+1.3	+2,718.0	+15.2	-48.0	-.3	28,835.0	160.9	906.0	4.2	29,741.0	165.1	1,005.0	6.3	+921.0	+5.1	31,667.0	176.5	+80.0	+.2	1,277.0	4.9	+1,465.0	-.8	-	-	34,489.0	180.8
Louisiana	594,853.0	3,320.8	-2,508.0	-13.9	-297,766.0	-1,661.9	-982.0	-5.5	293,597.0	1,639.5	26,930.0	124.4	320,527.0	1,763.9	-4,180.0	-26.3	+10,696.0	+59.0	327,043.0	1,796.6	-2,766.0	-15.1	34,347.0	132.8	-269,099.0	-1,457.6	-	-	89,525.0	456.7
Oklahoma	203,441.0	1,135.7	+1,709.0	+9.6	-65,180.0	-363.7	-5.0	Neg.	139,965.0	781.6	11,705.0	54.1	151,670.0	835.7	355.0	2.2	+3,609.0	+19.9	155,634.0	857.8	+612.0	+3.3	18,564.0	71.8	-101,198.0	-535.6	-	-	73,612.0	397.3
Texas	1,000,749.0	5,585.1	+4,483.0	+25.1	-113,377.0	-632.7	-2,176.0	-12.1	889,679.0	4,965.4	115,482.0	533.5	1,005,161.0	5,498.9	-14,954.0	-94.0	+21,939.0	+121.0	1,012,146.0	5,525.9	-111.0	+.3	118,715.0	459.9	-683,058.0	-3,699.1	-	-	447,692.0	2,287.0
New Mexico	119,166.0	665.3	-1,083.0	-6.1	-106,471.0	-594.2	-53.0	-.3	11,559.0	64.7	1,074.0	5.0	12,633.0	69.7	-10.0	-.1	+34.0	+.2	12,657.0	69.8	+71.0	Neg.	16,229.0	61.7	-8,579.0	-23.9	-	-	20,378.0	107.6
Kansas	104,733.0	584.7	+1,164.0	+6.5	+7,155.0	+39.9	-48.0	-.3	113,004.0	630.8	6,709.0	31.0	119,713.0	661.8	601.0	3.8	+179.0	+1.0	120,493.0	666.6	+233.0	+.7	9,507.0	36.8	-73,475.0	-389.9	-	-	56,758.0	314.2
Subtotal IIb	2,048,872.0	11,436.3	+4,000.0	+22.5	-572,921.0	-3,197.4	-3,312.0	-18.5	1,476,639.0	8,242.9	162,806.0	752.2	1,639,445.0	8,995.1	-17,183.0	-108.1	+37,378.0	+206.2	1,659,640.0	9,093.2	-1,881.0	-10.6	198,639.0	767.9	-1,133,944.0	-6,106.9	-	-	722,454.0	3,743.6
Subtotal II	2,092,730.0	11,681.1	+3,843.0	+21.7	-543,671.0	-3,033.8	-3,995.0	-22.4	1,548,907.0	8,646.6	165,157.0	763.0	1,714,064.0	9,409.6	-15,626.0	-98.3	+39,620.0	+218.5	1,738,058.0	9,529.8	-2,005.0	-12.1	199,638.0	771.8	-945,635.0	-5,121.4	-	-	990,056.0	[illegible]
Region III:																														
Subregion IIIa:																														
Montana	32,778.0	183.0	-184.0	-1.0	+645.0	-	-148.0	-.8	33,091.0	181.2	707.0	3.3	33,798.0	184.5	-284.0	-1.8	+56.0	+.3	33,570.0	183.0	+22.0	Neg.	1,262.0	4.9	-11,881.0	-64.9	-	-	22,973.0	123.0
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-17.0	-.2	-	-	+14,172.0	+77.2	-	-	14,155.0	77.0
Wyoming	138,314.0	772.2	+3,543.0	+19.8	-100,130.0	-558.8	-218.0	-1.2	41,509.0	232.0	1,744.0	8.1	43,253.0	240.1	-101.0	-.6	+546.0	+3.0	43,698.0	242.5	-193.0	-1.3	3,175.0	12.3	-23,576.0	-125.5	-	-	23,104.0	128.0
Utah	25,298.0	141.2	+113.0	+.6	+7,936.0	+44.3	-171.0	-1.0	33,176.0	185.1	2,511.0	11.6	35,687.0	196.7	-	-	+614.0	+3.4	36,301.0	200.1	-166.0	-1.0	-	-	-11,483.0	-62.9	-	-	24,652.0	136.2
Colorado	33,511.0	187.1	+23.0	+.1	-20,613.0	-115.0	-146.0	-.8	12,775.0	71.4	58.0	.3	12,833.0	71.7	-	-	+316.0	+1.7	13,149.0	73.4	-37.0	-.2	1,924.0	7.4	+18,460.0	+98.9	-	-	33,496.0	179.5
Washington	-	-	-	-	+61,721.0	+344.5	-314.0	-1.8	61,407.0	342.7	-	-	61,407.0	342.7	-	-	-	-	61,407.0	342.7	-1,326.0	-8.3	-	-	+13,558.0	+75.9	-	-	73,639.0	410.3
Oregon	-	-	-	-	+2,525.0	+14.1	-1.0	Neg.	2,524.0	14.1	-	-	2,524.0	14.1	-	-	-	-	2,524.0	14.1	-125.0	-.8	-	-	+37,816.0	+209.5	-	-	40,215.0	222.8
Subtotal IIIa	229,901.0	1,283.5	+3,495.0	+19.5	-47,916.0	-270.9	-998.0	-5.6	184,482.0	1,026.5	5,020.0	23.3	189,502.0	1,049.8	-385.0	-2.4	+1,532.0	+8.4	190,649.0	1,055.8	-1,842.0	-11.8	6,361.0	24.6	+37,066.0	+208.2	-	-	232,234.0	1,276.8
Subregion IIIb:																														
Arizona	97.0	.5	-2.0	Neg.	-95.0	-.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+1.0	Neg.	-	-	+22,951.0	+121.7	-	-	22,952.0	121.7
Nevada	209.0	1.1	-4.0	Neg.	-205.0	-1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1.0	Neg.	-	-	+10,336.0	+55.4	-	-	10,335.0	55.4
California	316,428.0	1,766.5	-108.0	-.6	+98,515.0	+550.2	-1,833.0	-10.3	413,002.0	2,305.8	24,815.0	114.7	437,817.0	2,420.5	8,748.0	55.0	+8,196.0	+45.2	454,761.0	2,520.7	-10,221.0	-63.7	-	-	-61,274.0	-354.1	-	-	383,266.0	2,102.9
Subtotal IIIb	316,734.0	1,768.1	-114.0	-.6	+98,215.0	+548.6	-1,833.0	-10.3	413,002.0	2,305.8	24,815.0	114.7	437,817.0	2,420.5	8,748.0	55.0	+8,196.0	+45.2	454,761.0	2,520.7	-10,221.0	-63.7	-	-	-27,987.0	-177.0	-	-	416,553.0	2,280.0
Subregion IIIc:																														
Alaska	11,128.0	62.1	-82.0	-.5	-3,427.0	-19.1	-48.0	-.3	7,571.0	42.2	-	-	7,571.0	42.2	151.0	.9	+142.0	+.8	7,864.0	43.9	-122.0	-.7	-	-	+6,216.0	+34.6	-	-	13,958.0	77.8
Hawaii	-	-	-	-	+12,693.0	+71.1	-75.0	-.4	12,618.0	70.7	-	-	12,618.0	70.7	252.0	1.6	+236.0	+1.3	13,106.0	73.6	-242.0	-1.5	-	-	+12,609.0	+74.5	-	-	25,473.0	146.6
Subtotal IIIc	11,128.0	62.1	-82.0	-.5	+9,266.0	+52.0	-123.0	-.7	20,189.0	112.9	-	-	20,189.0	112.9	403.0	2.5	+378.0	+2.1	20,970.0	117.5	-364.0	-2.2	-	-	+18,825.0	+109.1	-	-	39,431.0	224.4
Subtotal III	557,763.0	3,113.7	+3,299.0	+18.4	+59,565.0	+329.7	-2,954.0	-16.6	617,673.0	3,445.2	29,835.0	138.0	647,508.0	3,583.2	8,766.0	55.1	+10,106.0	+55.7	666,380.0	3,694.0	-12,427.0	-77.7	6,361.0	24.6	+27,904.0	+140.3	-	-	688,218.0	3,781.2
Foreign	-	-	+1,364.0	+7.6	-1,364.0	-7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unaccounted for	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-5,876.0	-139.5	-	-	-10,632.0	-65.3	-27,400.0	-151.3	-43,908.0	-356.1

Neg.--Negligible.

[1]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[2]Net foreign trade, at the national level, is equal to net shipments and is not additive to horizontal totals.

TA1

nsfers tural liquid ousanc rrels
5,793.(
-
-
-
-
-
-
-
310
1,616
13
-
-
-
-
-
-
-
-
14
[illegible]
[illegible]
8
3
3,3
5,2
9,0
[illegible]
14,
17,

TABLE 5. - Supply and demand for liquefied gases by major consumer sector, by States and Regions

1960

State and Region	Supply: Refinery output and natural gas process-plant product, Thousand barrels	Supply: Refinery output and natural gas process-plant product, Trillion Btu	Supply: Stock change[2], Thousand barrels	Supply: Stock change[2], Trillion Btu	Supply: Net shipments[3], Thousand barrels	Supply: Net shipments[3], Trillion Btu	Supply: Input at refineries, Thousand barrels	Supply: Input at refineries, Trillion Btu	Supply: Total supply available for consumption, Thousand barrels	Supply: Total supply available for consumption, Trillion Btu	Demand by major consumer sector[1]: Household and commercial, Thousand barrels	Household and commercial, Trillion Btu	Industrial, Thousand barrels	Industrial, Trillion Btu	Transportation, Thousand barrels	Transportation, Trillion Btu	Miscellaneous and unaccounted for, Thousand barrels	Miscellaneous and unaccounted for, Trillion Btu	Total domestic demand, Thousand barrels	Total domestic demand, Trillion Btu
United States total.	278,627.0	1,117.2	-4,822.0	-19.4	-2,504.0	-9.6	-45,375.0	-181.7	225,926.0	906.5	100,584.0	403.5	102,576.0	411.5	21,379.0	85.8	1,387.0	5.7	225,926.0	906.5
Region I:																				
Subregion Ia:																				
Maine	-	-	-	-	+431.0	+1.7	-	-	431.0	1.7	404.0	1.6	23.0	.1	3.0	Neg.	1.0	Neg.	431.0	1.7
New Hampshire	-	-	-	-	+532.0	+2.1	-	-	532.0	2.1	484.0	1.9	47.0	.2	1.0	Neg.	-	-	532.0	2.1
Vermont	-	-	-	-	+403.0	+1.6	-	-	403.0	1.6	304.0	1.2	98.0	.4	1.0	Neg.	-	-	403.0	1.6
Massachusetts	236.0	.9	+1.0	Neg.	+902.0	+3.7	-	-	1,139.0	4.6	884.0	3.5	218.0	.9	17.0	.1	20.0	.1	1,139.0	4.6
Rhode Island	-	-	-	-	+207.0	+.8	-	-	207.0	.8	175.0	.7	26.0	.1	6.0	Neg.	-	-	207.0	.8
Connecticut	-	-	-	-	+1,044.0	+4.2	-	-	1,044.0	4.2	735.0	3.0	236.0	.9	8.0	Neg.	65.0	.3	1,044.0	4.2
New York	459.0	1.8	+18.0	+.1	+2,606.0	+10.5	-	-	3,083.0	12.4	2,506.0	10.1	495.0	2.0	79.0	.3	3.0	Neg.	3,083.0	12.4
New Jersey	4,323.0	17.3	-293.0	-1.2	-236.0	-.9	-178.0	-.7	3,616.0	14.5	867.0	3.5	2,721.0	10.9	27.0	.1	1.0	Neg.	3,616.0	14.5
Pennsylvania	3,154.0	12.6	+59.0	+.2	-384.0	-1.5	-459.0	-1.8	2,370.0	9.5	1,323.0	5.3	960.0	3.9	85.0	.3	2.0	Neg.	2,370.0	9.5
Delaware	1,640.0	6.5	+17.0	+.1	-1,378.0	-5.6	-	-	279.0	1.0	207.0	.8	58.0	.2	10.0	Neg.	4.0	Neg.	279.0	1.0
Maryland	-	-	-	-	+1,008.0	+4.1	-	-	1,008.0	4.1	726.0	2.9	243.0	1.0	38.0	.2	1.0	Neg.	1,008.0	4.1
District of Columbia	-	-	-	-	Neg.	Neg.	-	-	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	-	-	Neg.	Neg.
Virginia	560.0	2.2	-2.0	Neg.	+569.0	+2.4	-	-	1,127.0	4.6	863.0	3.5	218.0	.9	31.0	.1	15.0	.1	1,127.0	4.6
West Virginia	7,885.0	31.7	+21.0	+.1	+499.0	+2.0	-	-	8,405.0	33.8	266.0	1.1	8,131.0	32.7	8.0	Neg.	-	-	8,405.0	33.8
North Carolina	-	-	-	-	+2,342.0	+9.4	-	-	2,342.0	9.4	1,901.0	7.6	254.0	1.0	23.0	.1	164.0	.7	2,342.0	9.4
South Carolina	-	-	-	-	+1,357.0	+5.4	-	-	1,357.0	5.4	1,089.0	4.4	179.0	.7	58.0	.2	31.0	.1	1,357.0	5.4
Georgia	-	-	-	-	+3,625.0	+14.4	-	-	3,625.0	14.4	2,681.0	10.7	571.0	2.3	286.0	1.1	87.0	.3	3,625.0	14.4
Florida	-	-	-	-	+4,935.0	+19.6	-	-	4,935.0	19.6	4,069.0	16.2	481.0	1.9	357.0	1.4	28.0	.1	4,935.0	19.6
Kentucky	5,701.0	22.9	-23.0	-.1	-2,211.0	-8.9	-	-	3,467.0	13.9	1,643.0	6.6	1,676.0	6.7	147.0	.6	1.0	Neg.	3,467.0	13.9
Tennessee	-	-	-	-	+1,328.0	+5.4	-	-	1,328.0	5.4	1,015.0	4.1	214.0	.9	95.0	.4	4.0	Neg.	1,328.0	5.4
Alabama	27.0	.1	-	-	+2,655.0	+10.6	-	-	2,682.0	10.7	2,473.0	9.9	73.0	.3	133.0	.5	3.0	Neg.	2,682.0	10.7
Mississippi	715.0	2.9	-357.0	-1.4	+4,238.0	+17.0	-659.0	-2.6	3,937.0	15.9	2,882.0	11.6	55.0	.2	961.0	3.9	39.0	.2	3,937.0	15.9
Ohio	2,753.0	10.9	+65.0	+.3	+98.0	+.4	-106.0	-.4	2,810.0	11.2	2,059.0	8.3	584.0	2.3	157.0	.6	10.0	Neg.	2,810.0	11.2
Subtotal Ia	27,453.0	109.8	-494.0	-1.9	+24,570.0	+98.4	-1,402.0	-5.5	50,127.0	200.8	29,556.0	118.5	17,561.0	70.5	2,531.0	9.9	479.0	1.9	50,127.0	200.8
Subregion Ib:																				
Indiana	745.0	3.0	+6.0	Neg.	+5,928.0	+23.8	-1,076.0	-4.3	5,603.0	22.5	3,987.0	16.0	1,388.0	5.6	206.0	.8	22.0	.1	5,603.0	22.5
Illinois	12,093.0	48.4	-258.0	-1.0	+3,736.0	+15.0	-2,003.0	-8.0	13,568.0	54.4	6,108.0	24.5	6,033.0	24.2	1,379.0	5.5	48.0	.2	13,568.0	54.4
Michigan	1,314.0	5.3	-55.0	-.2	+1,870.0	+7.5	-	-	3,129.0	12.6	2,282.0	9.2	744.0	3.0	92.0	.4	11.0	Neg.	3,129.0	12.6
Wisconsin	-	-	-98.0	-.4	+4,366.0	+17.5	-	-	4,268.0	17.1	3,147.0	12.6	1,007.0	4.0	101.0	.4	13.0	.1	4,268.0	17.1
Subtotal Ib	14,152.0	56.7	-405.0	-1.6	+15,900.0	+63.8	-3,079.0	-12.3	26,568.0	106.6	15,524.0	62.3	9,172.0	36.8	1,778.0	7.1	94.0	.4	26,568.0	106.6
Subtotal I	41,605.0	166.5	-899.0	-3.5	+40,470.0	+162.2	-4,481.0	-17.8	76,695.0	307.4	45,080.0	180.8	26,733.0	107.3	4,309.0	17.0	573.0	2.3	76,695.0	307.4
Region II:																				
Subregion IIa:																				
Minnesota	-	-	-19.0	-.1	+4,702.0	+18.9	-85.0	-.3	4,598.0	18.5	3,657.0	14.7	787.0	3.2	119.0	.5	35.0	.1	4,598.0	18.5
Iowa	-	-	-98.0	-.4	+4,306.0	+17.3	-	-	4,208.0	16.9	3,896.0	15.6	149.0	.6	99.0	.4	64.0	.3	4,208.0	16.9
Missouri	-	-	-99.0	-.4	+6,425.0	+25.9	-218.0	-.9	6,108.0	24.6	5,513.0	22.1	394.0	1.6	188.0	.8	13.0	.1	6,108.0	24.6
North Dakota	2,130.0	8.5	-96.0	-.4	-398.0	-1.6	-399.0	-1.6	1,237.0	4.9	926.0	3.7	184.0	.7	127.0	.5	-	-	1,237.0	4.9
South Dakota	-	-	-	-	+1,370.0	+5.5	-	-	1,370.0	5.5	1,256.0	5.0	15.0	.1	94.0	.4	5.0	Neg.	1,370.0	5.5
Nebraska	1,078.0	4.3	-99.0	-.4	+1,673.0	+6.7	-	-	2,652.0	10.6	2,106.0	8.4	52.0	.2	449.0	1.8	45.0	.2	2,652.0	10.6
Subtotal IIa	3,208.0	12.8	-411.0	-1.7	+18,078.0	+72.7	-702.0	-2.8	20,173.0	81.0	17,354.0	69.5	1,581.0	6.4	1,076.0	4.4	162.0	.7	20,173.0	81.0
Subregion IIb:																				
Arkansas	2,072.0	8.3	+2.0	Neg.	+2,868.0	+11.6	-120.0	-.5	4,822.0	19.4	3,331.0	13.4	125.0	.5	1,348.0	5.4	18.0	.1	4,822.0	19.4
Louisiana	30,772.0	123.5	-691.0	-2.8	-9,081.0	-36.4	-6,451.0	-25.9	14,549.0	58.4	1,843.0	7.4	11,737.0	47.1	860.0	3.5	109.0	.4	14,549.0	58.4
Oklahoma	22,406.0	89.9	+106.0	+.4	-11,205.0	-44.9	-3,976.0	-15.9	7,331.0	29.5	4,633.0	18.6	1,361.0	5.5	1,266.0	5.1	71.0	.3	7,331.0	29.5
Texas	130,302.0	522.7	-2,499.0	-10.0	-32,574.0	-130.6	-20,340.0	-81.5	74,889.0	300.6	11,862.0	47.6	53,962.0	216.4	8,839.0	35.7	226.0	.9	74,889.0	300.6
New Mexico	15,417.0	61.8	+48.0	+.2	-12,748.0	-51.1	-233.0	-.9	2,484.0	10.0	1,695.0	6.8	181.0	.7	543.0	2.2	65.0	.3	2,484.0	10.0
Kansas	4,692.0	18.9	-313.0	-1.3	+2,452.0	+9.9	-1,534.0	-6.1	5,297.0	21.4	4,055.0	16.3	289.0	1.2	937.0	3.8	16.0	.1	5,297.0	21.4
Subtotal IIb	205,661.0	825.1	-3,347.0	-13.5	-60,288.0	-241.5	-32,654.0	-130.8	109,372.0	439.3	27,419.0	110.1	67,655.0	271.4	13,793.0	55.7	505.0	2.1	109,372.0	439.3
Subtotal II	208,869.0	837.9	-3,758.0	-15.2	-42,210.0	-168.8	-33,356.0	-133.6	129,545.0	520.3	44,773.0	179.6	69,236.0	277.8	14,869.0	60.1	667.0	2.8	129,545.0	520.3
Region III:																				
Subregion IIIa:																				
Montana	2,522.0	10.1	-4.0	Neg.	-1,373.0	-5.5	-315.0	-1.3	830.0	3.3	596.0	2.4	109.0	.4	125.0	.5	-	-	830.0	3.3
Idaho	-	-	-	-	+455.0	+1.8	-	-	455.0	1.8	369.0	1.5	55.0	.2	31.0	.1	-	-	455.0	1.8
Wyoming	3,144.0	12.6	+6.0	Neg.	-1,521.0	-6.1	-546.0	-2.2	1,083.0	4.3	660.0	2.6	117.0	.5	305.0	1.2	1.0	Neg.	1,083.0	4.3
Utah	591.0	2.4	+2.0	Neg.	+615.0	+2.5	-710.0	-2.9	498.0	2.0	292.0	1.2	53.0	.2	153.0	.6	-	-	498.0	2.0
Colorado	2,754.0	11.0	+1.0	Neg.	+238.0	+1.0	-	-	2,993.0	12.0	2,467.0	9.9	99.0	.4	407.0	1.6	20.0	.1	2,993.0	12.0
Washington	-	-	-	-	+556.0	+2.2	-	-	556.0	2.2	408.0	1.6	122.0	.5	26.0	.1	-	-	556.0	2.2
Oregon	-	-	-	-	+1,185.0	+4.8	-	-	1,185.0	4.8	596.0	2.4	545.0	2.2	42.0	.2	2.0	Neg.	1,185.0	4.8
Subtotal IIIa	9,011.0	36.1	+5.0	Neg.	+155.0	+.7	-1,571.0	-6.4	7,600.0	30.4	5,388.0	21.6	1,100.0	4.4	1,089.0	4.3	23.0	.1	7,600.0	30.4
Subregion IIIb:																				
Arizona	-	-	-	-	+724.0	+2.9	-	-	724.0	2.9	467.0	1.9	104.0	.4	151.0	.6	2.0	Neg.	724.0	2.9
Nevada	-	-	-	-	+773.0	+3.1	-	-	773.0	3.1	323.0	1.3	429.0	1.7	21.0	.1	-	-	773.0	3.1
California	19,142.0	76.7	-170.0	-.7	-2,574.0	-10.3	-5,967.0	-23.9	10,431.0	41.8	4,444.0	17.8	4,934.0	19.8	932.0	3.7	121.0	.5	10,431.0	41.8
Subtotal IIIb	19,142.0	76.7	-170.0	-.7	-1,077.0	-4.3	-5,967.0	-23.9	11,928.0	47.8	5,234.0	21.0	5,467.0	21.9	1,104.0	4.4	123.0	.5	11,928.0	47.8
Subregion IIIc:																				
Alaska	-	-	-	-	+46.0	+.2	-	-	46.0	.2	42.0	.2	3.0	Neg.	-	-	1.0	Neg.	46.0	.2
Hawaii	-	-	-	-	+112.0	+.4	-	-	112.0	.4	67.0	.3	37.0	.1	8.0	Neg.	-	-	112.0	.4
Subtotal IIIc	-	-	-	-	+158.0	+.6	-	-	158.0	.6	109.0	.5	40.0	.1	8.0	Neg.	1.0	Neg.	158.0	.6
Subtotal III	28,153.0	112.8	-165.0	-.7	-764.0	-3.0	-7,538.0	-30.3	19,686.0	78.8	10,731.0	43.1	6,607.0	26.4	2,201.0	8.7	147.0	.6	19,686.0	78.8

Neg

1 Electricity generation, utilities, sector does not apply to this commodity.

2 Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

3 Includes net foreign trade: -1,357.0 thousand barrels; -54.3 trillion Btu.

TABLE 4. - Demand for petroleum products by major consumer sectors, by States and Regions

1965

State and Region	Major products by consumer sectors												Miscellaneous products unaccounted for		Apparent total domestic demand	
	Household and commercial		Industrial		Transportation		Electricity generation, utilities		Miscellaneous and unaccounted for		Total					
	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States total.	843,673.0	4,743.3	395,786.0	2,111.6	2,274,680.0	12,184.2	118,545.0	743.4	77,350.0	457.5	3,710,034.0	20,240.0	492,390.0	2,743.2	4,202,424.0	22,983.2
Region 1:																
Subregion 1a:																
Maine	10,302.0	59.1	1,592.0	9.6	14,686.0	78.3	4,694.0	29.4	103.0	.7	31,377.0	177.1	-	-	31,377.0	177.1
New Hampshire	7,119.0	40.5	996.0	5.9	7,215.0	37.9	1,375.0	8.6	109.0	.6	16,816.0	93.5	-	-	16,816.0	93.5
Vermont	5,645.0	32.3	530.0	3.1	3,912.0	20.6	67.0	.4	80.0	.5	10,232.0	56.9	-	-	10,232.0	56.9
Massachusetts	85,865.0	510.9	10,790.0	66.3	47,539.0	254.7	13,106.0	82.4	608.0	3.6	157,908.0	917.9	2,153.0	11.9	160,061.0	929.8
Rhode Island	8,198.0	47.8	1,763.0	10.9	9,919.0	55.0	1,022.0	6.4	338.0	2.1	21,240.0	122.2	3,665.0	21.5	24,905.0	143.7
Connecticut	25,073.0	146.3	11,026.0	67.8	27,805.0	147.9	2,721.0	17.1	266.0	1.5	66,891.0	380.6	-	-	66,891.0	380.6
New York	149,951.0	892.5	17,086.0	103.1	168,785.0	916.6	23,315.0	146.6	2,650.0	15.8	361,787.0	2,074.6	3,475.0	21.6	365,262.0	2,096.2
New Jersey	55,011.0	322.2	21,125.0	125.0	72,190.0	389.9	12,670.0	79.6	1,849.0	11.1	162,845.0	927.8	31,568.0	195.9	194,413.0	1,123.7
Pennsylvania	54,349.0	318.3	28,661.0	175.0	102,298.0	547.4	4,096.0	25.7	4,105.0	24.6	193,509.0	1,091.0	33,208.0	208.0	226,717.0	1,299.0
Delaware	4,250.0	24.3	4,352.0	27.1	6,774.0	36.4	114.0	.7	592.0	3.6	16,082.0	92.1	3,713.0	34.1	19,795.0	126.2
Maryland	19,251.0	112.0	6,404.0	39.2	38,243.0	208.4	607.0	3.8	1,606.0	9.6	66,111.0	373.0	3,107.0	16.9	69,218.0	389.9
District of Columbia	8,709.0	53.6	219.0	1.4	6,255.0	33.2	92.0	.6	329.0	2.0	15,604.0	90.8	-	-	15,604.0	90.8
Virginia	19,810.0	113.7	4,822.0	29.2	58,704.0	322.7	220.0	1.3	1,554.0	9.2	85,110.0	476.1	2,262.0	15.4	87,372.0	491.5
West Virginia	1,254.0	6.8	12,343.0	54.7	14,252.0	75.6	72.0	.5	310.0	1.8	28,231.0	139.4	-	-	28,231.0	139.4
North Carolina	24,378.0	134.9	6,447.0	38.1	50,068.0	266.0	74.0	.4	2,658.0	15.2	83,625.0	454.6	-	-	83,625.0	454.6
South Carolina	7,087.0	37.9	2,865.0	16.9	24,803.0	132.4	32.0	.2	1,499.0	9.0	36,286.0	196.4	-	-	36,286.0	196.4
Georgia	6,436.0	31.0	7,851.0	47.7	47,806.0	254.2	52.0	.3	3,179.0	18.7	65,324.0	351.9	2,425.0	13.4	67,749.0	365.3
Florida	12,127.0	61.7	11,813.0	71.8	82,838.0	446.1	28,060.0	176.3	6,197.0	38.0	141,035.0	793.9	249.0	1.4	141,284.0	795.3
Kentucky	5,670.0	29.3	4,285.0	19.3	30,977.0	164.4	15.0	.1	821.0	4.8	41,768.0	217.9	2,987.0	18.8	44,755.0	236.7
Tennessee	3,785.0	19.3	2,276.0	12.4	38,297.0	203.4	2.0	Neg.	1,316.0	7.8	45,676.0	242.9	4,399.0	24.9	50,075.0	267.8
Alabama	4,306.0	19.3	1,825.0	10.7	34,595.0	184.7	-	-	1,113.0	6.6	41,839.0	221.3	1,945.0	10.5	43,784.0	231.8
Mississippi	3,721.0	15.5	744.0	4.3	21,445.0	112.4	17.0	.1	1,108.0	6.4	27,035.0	138.7	46,417.0	257.8	73,452.0	396.5
Ohio	22,316.0	124.5	13,149.0	78.5	101,180.0	537.4	245.0	1.4	3,052.0	18.2	139,942.0	760.0	25,114.0	157.5	165,056.0	917.5
Subtotal 1a	544,613.0	3,153.7	172,964.0	1,018.0	1,010,586.0	5,425.6	92,668.0	581.9	35,442.0	211.4	1,856,273.0	10,390.6	166,687.0	1,009.6	2,022,960.0	11,400.2
Subregion 1b:																
Indiana	26,307.0	145.1	15,234.0	90.7	64,575.0	345.2	164.0	1.0	1,113.0	6.4	107,393.0	588.4	27,149.0	142.6	134,542.0	731.0
Illinois	49,802.0	282.8	20,618.0	108.2	103,748.0	552.1	285.0	1.7	2,181.0	12.9	176,634.0	957.7	29,536.0	190.1	206,170.0	1,147.8
Michigan	32,870.0	186.3	9,909.0	57.6	85,838.0	453.5	413.0	2.4	1,901.0	11.2	130,931.0	711.0	1,508.0	11.4	132,439.0	722.4
Wisconsin	27,104.0	150.4	2,788.0	15.5	39,472.0	208.7	69.0	.4	922.0	5.3	70,355.0	380.3	1,592.0	8.3	71,947.0	388.6
Subtotal 1b	136,083.0	764.6	48,549.0	272.0	293,633.0	1,559.5	931.0	5.5	6,117.0	35.8	485,313.0	2,637.4	59,785.0	352.4	545,098.0	2,989.8
Subtotal I	680,696.0	3,918.3	221,513.0	1,290.0	1,304,219.0	6,985.1	93,599.0	587.4	41,559.0	247.2	2,341,586.0	13,028.0	226,472.0	1,362.0	2,568,058.0	14,390.0
Region II:																
Subregion IIa:																
Minnesota	21,112.0	114.6	5,418.0	31.1	41,215.0	219.0	447.0	2.8	1,617.0	9.4	69,809.0	376.9	3,770.0	23.3	73,579.0	400.2
Iowa	14,417.0	73.8	1,308.0	6.9	34,376.0	181.4	224.0	1.3	1,248.0	7.2	51,573.0	270.6	-	-	51,573.0	270.6
Missouri	15,094.0	75.6	2,166.0	12.7	55,835.0	297.9	150.0	.8	1,470.0	8.6	74,715.0	395.6	5,195.0	30.4	79,910.0	426.0
North Dakota	4,555.0	24.9	1,012.0	5.9	11,529.0	61.0	-	-	644.0	3.8	17,740.0	95.6	-	-	17,740.0	95.6
South Dakota	4,490.0	23.6	2,120.0	8.6	11,583.0	61.1	45.0	.3	494.0	2.9	18,732.0	96.5	-	-	18,732.0	96.5
Nebraska	5,153.0	24.6	381.0	2.0	19,771.0	104.5	206.0	1.3	557.0	3.2	26,068.0	135.6	-	-	26,068.0	135.6
Subtotal IIa	64,821.0	337.1	12,405.0	67.2	174,309.0	924.9	1,072.0	6.5	6,030.0	35.1	258,637.0	1,370.8	8,965.0	53.7	267,602.0	1,424.5
Subregion IIb:																
Arkansas	4,508.0	18.9	831.0	4.8	21,354.0	111.3	32.0	.2	612.0	3.6	27,337.0	138.8	7,152.0	42.0	34,489.0	180.8
Louisiana	3,454.0	15.4	21,727.0	93.0	46,260.0	253.6	69.0	.4	1,243.0	7.3	72,753.0	369.7	16,772.0	87.0	89,525.0	456.7
Oklahoma	6,747.0	29.3	1,154.0	6.2	36,153.0	189.1	52.0	.3	678.0	4.0	44,784.0	228.9	28,828.0	168.4	73,612.0	397.3
Texas	17,332.0	72.9	90,606.0	377.5	187,621.0	989.3	50.0	.3	4,892.0	28.4	300,501.0	1,468.4	147,191.0	818.6	447,692.0	2,287.0
New Mexico	2,398.0	10.9	403.0	2.1	15,602.0	82.7	40.0	.2	1,935.0	11.7	20,378.0	107.6	-	-	20,378.0	107.6
Kansas	7,119.0	32.6	1,602.0	8.2	32,787.0	173.0	311.0	1.9	1,000.0	6.0	42,819.0	221.7	13,939.0	92.5	56,758.0	314.2
Subtotal IIb	41,558.0	180.0	116,323.0	491.8	339,777.0	1,799.0	554.0	3.3	10,360.0	61.0	508,572.0	2,535.1	213,882.0	1,208.5	722,454.0	3,743.6
Subtotal II	106,379.0	517.1	128,728.0	559.0	514,086.0	2,723.9	1,626.0	9.8	16,390.0	96.1	767,209.0	3,905.9	222,847.0	1,262.2	1,990,056.0	5,168.1
Region III:																
Subregion IIIa:																
Montana	2,587.0	14.0	773.0	4.2	13,551.0	73.0	-	-	960.0	5.7	17,871.0	96.9	5,102.0	26.1	22,973.0	123.0
Idaho	3,696.0	20.8	695.0	3.9	9,109.0	48.5	1.0	Neg.	654.0	3.8	14,155.0	77.0	-	-	14,155.0	77.0
Wyoming	1,427.0	7.3	1,708.0	9.8	7,919.0	43.5	36.0	.2	699.0	4.1	11,789.0	64.9	11,315.0	63.1	23,104.0	128.0
Utah	2,421.0	13.2	3,603.0	22.4	14,521.0	78.0	1,607.0	10.1	500.0	3.0	22,652.0	126.7	2,000.0	9.5	24,652.0	136.2
Colorado	4,733.0	22.9	1,141.0	6.8	24,940.0	133.6	37.0	.2	1,251.0	7.2	32,102.0	170.7	1,394.0	8.8	33,496.0	179.5
Washington	16,299.0	94.7	4,199.0	25.4	37,735.0	202.6	23.0	.1	3,285.0	19.9	61,541.0	342.7	12,098.0	67.6	73,639.0	410.3
Oregon	10,671.0	61.8	2,679.0	16.1	24,666.0	132.6	5.0	Neg.	1,679.0	10.0	39,700.0	220.5	515.0	2.3	40,215.0	222.8
Subtotal IIIa	41,834.0	234.7	14,798.0	88.6	132,441.0	711.8	1,709.0	10.6	9,028.0	53.7	199,810.0	1,099.4	32,424.0	177.4	232,234.0	1,276.8
Subregion IIIb:																
Arizona	1,133.0	5.1	755.0	4.3	20,327.0	108.1	6.0	Neg.	731.0	4.2	22,952.0	121.7	-	-	22,952.0	121.7
Nevada	1,314.0	6.7	357.0	1.9	8,408.0	45.3	10.0	.1	246.0	1.4	10,335.0	55.4	-	-	10,335.0	55.4
California	9,563.0	45.5	27,540.0	155.2	278,831.0	1,519.3	16,500.0	103.7	7,415.0	42.8	339,849.0	1,866.5	43,417.0	236.4	383,266.0	2,102.9
Subtotal IIIb	12,010.0	57.3	28,652.0	161.4	307,566.0	1,672.7	16,516.0	103.8	8,392.0	48.4	373,136.0	2,043.6	43,417.0	236.4	416,553.0	2,280.0
Subregion IIIc:																
Alaska	2,384.0	13.9	789.0	4.7	4,865.0	26.7	215.0	1.2	424.0	2.5	8,677.0	49.0	5,281.0	28.8	13,958.0	77.8
Hawaii	370.0	2.0	1,306.0	7.9	11,503.0	64.0	4,880.0	30.6	1,557.0	9.6	19,616.0	114.1	5,857.0	32.5	25,473.0	146.6
Subtotal IIIc	2,754.0	15.9	2,095.0	12.6	16,368.0	90.7	5,095.0	31.8	1,981.0	12.1	28,293.0	163.1	11,138.0	61.3	39,431.0	224.4
Subtotal III	56,598.0	307.9	45,545.0	262.6	456,375.0	2,475.2	23,320.0	146.2	19,401.0	114.2	601,239.0	3,306.1	86,979.0	475.1	688,218.0	3,781.2
Unaccounted for	-	-	-	-	-	-	-	-	-	-	-	-	-43,908.0	-356.1	-43,908.0	-356.1

Neg.--Negligible.

TABLE 6. - Supply and demand for jet fuel (excludes kerosine-type jet fuel) by major consumer sector, by States and Regions

1960

State and Region	Supply								Demand by major consumer sector[1]			
	Refinery output		Stock change[2]		Net shipments[3]		Total supply available for consumption		Transportation		Total domestic demand	
	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States total.	88,248.0	463.1	+2,285.0	+11.6	+12,001.0	+63.3	102,534.0	538.0	102,534.0	538.0	102,534.0	538.0
Region I:												
Subregion Ia:												
Maine	-	-	+8.0	Neg.	+3,162.0	+16.6	3,170.0	16.6	3,170.0	16.6	3,170.0	16.6
New Hampshire	-	-	+4.0	Neg.	+1,456.0	+7.7	1,460.0	7.7	1,460.0	7.7	1,460.0	7.7
Vermont	-	-	-	-	-	-	-	-	-	-	-	-
Massachusetts	-	-	+29.0	+.2	+208.0	+1.0	237.0	1.2	237.0	1.2	237.0	1.2
Rhode Island	-	-	+2.0	Neg.	+557.0	+2.9	559.0	2.9	559.0	2.9	559.0	2.9
Connecticut	-	-	+6.0	Neg.	+2,338.0	+12.3	2,344.0	12.3	2,344.0	12.3	2,344.0	12.3
New York	18.0	.1	+43.0	+.2	+2,953.0	+15.5	3,014.0	15.8	3,014.0	15.8	3,014.0	15.8
New Jersey	709.0	3.7	+171.0	+.9	-799.0	-4.2	81.0	.4	81.0	.4	81.0	.4
Pennsylvania	2,342.0	12.3	+150.0	+.8	-	-	2,492.0	13.1	2,492.0	13.1	2,492.0	13.1
Delaware	-	-	+2.0	Neg.	+283.0	+1.5	285.0	1.5	285.0	1.5	285.0	1.5
Maryland	-	-	+27.0	+.1	+434.0	+2.3	461.0	2.4	461.0	2.4	461.0	2.4
District of Columbia	-	-	-	-	-	-	-	-	-	-	-	-
Virginia	-	-	+23.0	+.1	+1,138.0	+6.0	1,161.0	6.1	1,161.0	6.1	1,161.0	6.1
West Virginia	-	-	+7.0	Neg.	+37.0	+.2	44.0	.2	44.0	.2	44.0	.2
North Carolina	-	-	+36.0	+.2	+971.0	+5.1	1,007.0	5.3	1,007.0	5.3	1,007.0	5.3
South Carolina	-	-	+19.0	+.1	+1,146.0	+6.0	1,165.0	6.1	1,165.0	6.1	1,165.0	6.1
Georgia	-	-	+31.0	+.2	+1,641.0	+8.6	1,672.0	8.8	1,672.0	8.8	1,672.0	8.8
Florida	89.0	.5	+30.0	+.2	+4,932.0	+25.8	5,051.0	26.5	5,051.0	26.5	5,051.0	26.5
Kentucky	1,203.0	6.3	-21.0	-.1	-13.0	-.1	1,169.0	6.1	1,169.0	6.1	1,169.0	6.1
Tennessee	1,000.0	5.2	+27.0	+.1	-219.0	-1.1	808.0	4.2	808.0	4.2	808.0	4.2
Alabama	533.0	2.8	+63.0	+.3	-232.0	-1.2	364.0	1.9	364.0	1.9	364.0	1.9
Mississippi	269.0	1.4	+27.0	+.1	+168.0	+.9	464.0	2.4	464.0	2.4	464.0	2.4
Ohio	2,733.0	14.3	+95.0	+.5	+56.0	+.3	2,884.0	15.1	2,884.0	15.1	2,884.0	15.1
Subtotal Ia	8,896.0	46.6	+779.0	+3.9	+20,217.0	+106.1	29,892.0	156.6	29,892.0	156.6	29,892.0	156.6
Subregion Ib:												
Indiana	1,773.0	9.4	+26.0	+.1	-1,043.0	-5.5	756.0	4.0	756.0	4.0	756.0	4.0
Illinois	668.0	3.5	+76.0	+.4	-292.0	-1.5	452.0	2.4	452.0	2.4	452.0	2.4
Michigan	385.0	2.0	-	-	+489.0	+2.6	874.0	4.6	874.0	4.6	874.0	4.6
Wisconsin	-	-	+3.0	Neg.	+966.0	+5.1	969.0	5.1	969.0	5.1	969.0	5.1
Subtotal Ib	2,826.0	14.9	+105.0	+.5	+120.0	+.7	3,051.0	16.1	3,051.0	16.1	3,051.0	16.1
Subtotal I	11,722.0	61.5	+884.0	+4.4	+20,337.0	+106.8	32,943.0	172.7	32,943.0	172.7	32,943.0	172.7
Region II:												
Subregion IIa:												
Minnesota	348.0	1.9	-34.0	-.2	-31.0	-.2	283.0	1.5	283.0	1.5	283.0	1.5
Iowa	-	-	-	-	+131.0	+.7	131.0	.7	131.0	.7	131.0	.7
Missouri	1,350.0	7.1	-1.0	Neg.	+319.0	+1.7	1,668.0	8.8	1,668.0	8.8	1,668.0	8.8
North Dakota	431.0	2.3	-30.0	-.2	+453.0	+2.4	854.0	4.5	854.0	4.5	854.0	4.5
South Dakota	-	-	+2.0	Neg.	+996.0	+5.2	998.0	5.2	998.0	5.2	998.0	5.2
Nebraska	-	-	-	-	+1,337.0	+7.0	1,337.0	7.0	1,337.0	7.0	1,337.0	7.0
Subtotal IIa	2,129.0	11.3	-63.0	-.4	+3,205.0	+16.8	5,271.0	27.7	5,271.0	27.7	5,271.0	27.7
Subregion IIb:												
Arkansas	54.0	.3	-10.0	-.1	+20.0	+.1	64.0	.3	64.0	.3	64.0	.3
Louisiana	8,344.0	43.7	+437.0	+2.3	-1,248.0	-6.5	7,533.0	39.5	7,533.0	39.5	7,533.0	39.5
Oklahoma	10,736.0	56.4	+167.0	+.9	-4,126.0	-21.7	6,777.0	35.6	6,777.0	35.6	6,777.0	35.6
Texas	27,460.0	144.0	+278.0	+1.5	-12,580.0	-66.0	15,158.0	79.5	15,158.0	79.5	15,158.0	79.5
New Mexico	1,368.0	7.2	+18.0	+.1	+742.0	+3.9	2,128.0	11.2	2,128.0	11.2	2,128.0	11.2
Kansas	4,286.0	22.6	-15.0	-.1	+1,723.0	+9.0	5,994.0	31.5	5,994.0	31.5	5,994.0	31.5
Subtotal IIb	52,248.0	274.2	+875.0	+4.6	-15,469.0	-81.2	37,654.0	197.6	37,654.0	197.6	37,654.0	197.6
Subtotal II	54,377.0	285.5	+812.0	+4.2	-12,264.0	-64.4	42,925.0	225.3	42,925.0	225.3	42,925.0	225.3
Region III:												
Subregion IIIa:												
Montana	2,468.0	13.0	+25.0	+.1	-1,892.0	-9.9	601.0	3.2	601.0	3.2	601.0	3.2
Idaho	-	-	+3.0	Neg.	+514.0	+2.7	517.0	2.7	517.0	2.7	517.0	2.7
Wyoming	611.0	3.2	+2.0	Neg.	-579.0	-3.0	34.0	.2	34.0	.2	34.0	.2
Utah	1,599.0	8.3	+35.0	+.2	-1,263.0	-6.6	371.0	1.9	371.0	1.9	371.0	1.9
Colorado	644.0	3.4	+3.0	Neg.	-272.0	-1.4	375.0	2.0	375.0	2.0	375.0	2.0
Washington	1,683.0	8.8	+43.0	+.2	+1,964.0	+10.4	3,690.0	19.4	3,690.0	19.4	3,690.0	19.4
Oregon	-	-	+27.0	+.1	+91.0	+.5	118.0	.6	118.0	.6	118.0	.6
Subtotal IIIa	7,005.0	36.7	+138.0	+.6	-1,437.0	-7.3	5,706.0	30.0	5,706.0	30.0	5,706.0	30.0
Subregion IIIb:												
Arizona	-	-	+12.0	+.1	+2,804.0	+14.7	2,816.0	14.8	2,816.0	14.8	2,816.0	14.8
Nevada	-	-	-	-	-	-	-	-	-	-	-	-
California	15,060.0	79.0	+432.0	+2.3	+2,461.0	+12.9	17,953.0	94.2	17,953.0	94.2	17,953.0	94.2
Subtotal IIIb	15,060.0	79.0	+444.0	+2.4	+5,265.0	+27.6	20,769.0	109.0	20,769.0	109.0	20,769.0	109.0
Subregion IIIc:												
Alaska	-	-	+3.0	Neg.	+33.0	+.2	36.0	.2	36.0	.2	36.0	.2
Hawaii	84.0	.4	+4.0	Neg.	+67.0	+.4	155.0	.8	155.0	.8	155.0	.8
Subtotal IIIc	84.0	.4	+7.0	Neg.	+100.0	+.6	191.0	1.0	191.0	1.0	191.0	1.0
Subtotal III	22,149.0	116.1	+589.0	+3.0	+3,928.0	+20.9	26,666.0	140.0	26,666.0	140.0	26,666.0	140.0

Neg.--Negligible.

[1]Household and commercial; industrial; electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.

[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[3]Includes net foreign trade: 12,525.0 thousand barrels; 65.8 trillion Btu.

TABLE 7. - Supply and demand for gasoline by major consumer sector, by States and Regions

1960

State and Region	Supply								Demand by major consumer sectors[1]			
	Refinery output		Stock change[2]		Net shipments[3]		Total supply available for consumption		Transportation		Total domestic demand	
	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States total.	1,510,134.0	7,925.4	-5,352.0	-28.1	-8,182.0	-43.1	1,496,600.0	7,854.2	1,496,600.0	7,854.2	1,496,600.0	7,854.2
Region I:												
Subregion Ia:												
Maine..........	-	-	-15.0	-.1	+8,218.0	+43.1	8,203.0	43.0	8,203.0	43.0	8,203.0	43.0
New Hampshire...	-	-	-7.0	Neg.	+4,996.0	+26.2	4,989.0	26.2	4,989.0	26.2	4,989.0	26.2
Vermont.........	-	-	-7.0	Neg.	+3,245.0	+17.0	3,238.0	17.0	3,238.0	17.0	3,238.0	17.0
Massachusetts...	5,303.0	27.8	-57.0	-.3	+29,569.0	+155.2	34,815.0	182.7	34,815.0	182.7	34,815.0	182.7
Rhode Island....	-	-	-3.0	Neg.	+5,938.0	+31.1	5,935.0	31.1	5,935.0	31.1	5,935.0	31.1
Connecticut.....	-	-	-15.0	-.1	+18,837.0	+98.9	18,822.0	98.8	18,822.0	98.8	18,822.0	98.8
New York........	12,259.0	64.3	-14.0	-.1	+90,678.0	+476.0	102,923.0	540.2	102,923.0	540.2	102,923.0	540.2
New Jersey......	66,508.0	349.1	-22.0	-.1	-17,636.0	-92.6	48,850.0	256.4	48,850.0	256.4	48,850.0	256.4
Pennsylvania....	90,626.0	475.5	-85.0	-.4	-11,895.0	-62.4	78,646.0	412.7	78,646.0	412.7	78,646.0	412.7
Delaware........	20,328.0	106.6	-212.0	-1.1	-15,269.0	-80.1	4,847.0	25.4	4,847.0	25.4	4,847.0	25.4
Maryland........	244.0	1.3	+61.0	+.3	+21,966.0	+115.3	22,271.0	116.9	22,271.0	116.9	22,271.0	116.9
District of Columbia.......	-	-	-	-	+4,833.0	+25.4	4,833.0	25.4	4,833.0	25.4	4,833.0	25.4
Virginia........	6,723.0	35.3	-45.0	-.2	+25,121.0	+131.8	31,799.0	166.9	31,799.0	166.9	31,799.0	166.9
West Virginia...	817.0	4.3	-15.0	-.1	+11,399.0	+59.8	12,201.0	64.0	12,201.0	64.0	12,201.0	64.0
North Carolina..	-	-	-66.0	-.3	+35,479.0	+186.1	35,413.0	185.8	35,413.0	185.8	35,413.0	185.8
South Carolina..	142.0	.7	-37.0	-.2	+17,582.0	+92.3	17,687.0	92.8	17,687.0	92.8	17,687.0	92.8
Georgia.........	-	-	-106.0	-.6	+31,860.0	+167.2	31,754.0	166.6	31,754.0	166.6	31,754.0	166.6
Florida.........	-	-	-51.0	-.3	+45,571.0	+239.2	45,520.0	238.9	45,520.0	238.9	45,520.0	238.9
Kentucky........	15,130.0	79.5	-13.0	-.1	+6,773.0	+35.5	21,890.0	114.9	21,890.0	114.9	21,890.0	114.9
Tennessee.......	1,730.0	9.1	-58.0	-.3	+27,424.0	+143.9	29,096.0	152.7	29,096.0	152.7	29,096.0	152.7
Alabama.........	92.0	.5	-4.0	Neg.	+24,202.0	+127.0	24,290.0	127.5	24,290.0	127.5	24,290.0	127.5
Mississippi.....	4,405.0	23.1	-93.0	-.5	+11,612.0	+61.0	15,924.0	83.6	15,924.0	83.6	15,924.0	83.6
Ohio............	74,135.0	389.2	-498.0	-2.6	+4,121.0	+21.6	77,758.0	408.2	77,758.0	408.2	77,758.0	408.2
Subtotal Ia...	298,442.0	1,566.3	-1,362.0	-7.1	+384,624.0	+2,018.5	681,704.0	3,577.7	681,704.0	3,577.7	681,704.0	3,577.7
Subregion Ib:												
Indiana.........	70,825.0	371.7	+339.0	+1.8	-27,604.0	-144.9	43,560.0	228.6	43,560.0	228.6	43,560.0	228.6
Illinois........	114,638.0	601.6	+2,155.0	+11.3	-43,149.0	-226.4	73,644.0	386.5	73,644.0	386.5	73,644.0	386.5
Michigan........	21,240.0	111.5	+390.0	+2.0	+44,152.0	+231.7	65,782.0	345.2	65,782.0	345.2	65,782.0	345.2
Wisconsin.......	1,123.0	5.9	-32.0	-.2	+31,623.0	+166.0	32,714.0	171.7	32,714.0	171.7	32,714.0	171.7
Subtotal Ib...	207,826.0	1,090.7	+2,852.0	+14.9	+5,022.0	+26.4	215,700.0	1,132.0	215,700.0	1,132.0	215,700.0	1,132.0
Subtotal I..	506,268.0	2,657.0	+1,490.0	+7.8	+389,646.0	+2,044.9	897,404.0	4,709.7	897,404.0	4,709.7	897,404.0	4,709.7
Region II:												
Subregion IIa:												
Minnesota.......	10,693.0	56.1	+1.0	Neg.	+22,246.0	+116.8	32,940.0	172.9	32,940.0	172.9	32,940.0	172.9
Iowa............	-	-	+4.0	Neg.	+28,854.0	+151.4	28,858.0	151.4	28,858.0	151.4	28,858.0	151.4
Missouri........	11,759.0	61.7	+352.0	+1.8	+29,783.0	+156.4	41,894.0	219.9	41,894.0	219.9	41,894.0	219.9
North Dakota....	9,250.0	48.6	+81.0	+.4	-1,384.0	-7.3	7,947.0	41.7	7,947.0	41.7	7,947.0	41.7
South Dakota....	-	-	-7.0	Neg.	+8,487.0	+44.5	8,480.0	44.5	8,480.0	44.5	8,480.0	44.5
Nebraska........	517.0	2.7	+15.0	+.1	+14,448.0	+75.8	14,980.0	78.6	14,980.0	78.6	14,980.0	78.6
Subtotal IIa..	32,219.0	169.1	+446.0	+2.3	+102,434.0	+537.6	135,099.0	709.0	135,099.0	709.0	135,099.0	709.0
Subregion IIb:												
Arkansas........	12,635.0	66.3	+14.0	+.1	+1,832.0	+9.6	14,481.0	76.0	14,481.0	76.0	14,481.0	76.0
Louisiana.......	137,222.0	720.1	-2,238.0	-11.7	-112,028.0	-587.9	22,956.0	120.5	22,956.0	120.5	22,956.0	120.5
Oklahoma........	72,634.0	381.1	-521.0	-2.7	-45,069.0	-236.5	27,044.0	141.9	27,044.0	141.9	27,044.0	141.9
Texas...........	437,812.0	2,297.6	-3,587.0	-18.8	-326,208.0	-1,711.9	108,017.0	566.9	108,017.0	566.9	108,017.0	566.9
New Mexico......	4,536.0	23.8	+9.0	Neg.	+5,098.0	+26.8	9,643.0	50.6	9,643.0	50.6	9,643.0	50.6
Kansas..........	61,669.0	323.7	+554.0	+2.9	-36,405.0	-191.1	25,818.0	135.5	25,818.0	135.5	25,818.0	135.5
Subtotal IIb..	726,508.0	3,812.6	-5,769.0	-30.2	-512,780.0	-2,691.0	207,959.0	1,091.4	207,959.0	1,091.4	207,959.0	1,091.4
Subtotal II.	758,727.0	3,981.7	-5,323.0	-27.9	-410,346.0	-2,153.4	343,058.0	1,800.4	343,058.0	1,800.4	343,058.0	1,800.4
Region III:												
Subregion IIIa:												
Montana.........	10,539.0	55.4	+25.0	+.1	-3,046.0	-16.0	7,518.0	39.5	7,518.0	39.5	7,518.0	39.5
Idaho...........	-	-	-6.0	Neg.	+6,771.0	+35.5	6,765.0	35.5	6,765.0	35.5	6,765.0	35.5
Wyoming.........	17,356.0	91.1	-165.0	-.9	-12,783.0	-67.1	4,408.0	23.1	4,408.0	23.1	4,408.0	23.1
Utah............	15,541.0	81.5	-39.0	-.2	-6,976.0	-36.6	8,526.0	44.7	8,526.0	44.7	8,526.0	44.7
Colorado........	6,205.0	32.6	+80.0	+.4	+10,932.0	+57.4	17,217.0	90.4	17,217.0	90.4	17,217.0	90.4
Washington......	17,595.0	92.4	-67.0	-.4	+10,965.0	+57.5	28,493.0	149.5	28,493.0	149.5	28,493.0	149.5
Oregon..........	-	-	-140.0	-.7	+16,532.0	+86.7	16,392.0	86.0	16,392.0	86.0	16,392.0	86.0
Subtotal IIIa.	67,236.0	353.0	-312.0	-1.7	+22,395.0	+117.4	89,319.0	468.7	89,319.0	468.7	89,319.0	468.7
Subregion IIIb:												
Arizona.........	-	-	-67.0	-.4	+12,576.0	+66.0	12,509.0	65.6	12,509.0	65.6	12,509.0	65.6
Nevada..........	-	-	-27.0	-.1	+3,823.0	+20.0	3,796.0	19.9	3,796.0	19.9	3,796.0	19.9
California......	177,903.0	933.7	-1,086.0	-5.7	-33,459.0	-175.6	143,358.0	752.4	143,358.0	752.4	143,358.0	752.4
Subtotal IIIb.	177,903.0	933.7	-1,180.0	-6.2	-17,060.0	-89.6	159,663.0	837.9	159,663.0	837.9	159,663.0	837.9
Subregion IIIc:												
Alaska..........	-	-	-20.0	-.1	+1,928.0	+10.1	1,908.0	10.0	1,908.0	10.0	1,908.0	10.0
Hawaii..........	-	-	-7.0	Neg.	+5,255.0	+27.5	5,248.0	27.5	5,248.0	27.5	5,248.0	27.5
Subtotal IIIc.	-	-	-27.0	-.1	+7,183.0	+37.6	7,156.0	37.5	7,156.0	37.5	7,156.0	37.5
Subtotal III	245,139.0	1,286.7	-1,519.0	-8.0	+12,518.0	+65.4	256,138.0	1,344.1	256,138.0	1,344.1	256,138.0	1,344.1

Neg.--Negligible.

[1]Household and commercial; industrial; electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.

[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[3]Includes net foreign trade: -3,678.0 thousand barrels; -19.3 trillion Btu.

TABLE 8. - Supply and demand for kerosine and kerosine-type jet fuel by major consumer sector, by States and Regions

1960

State and Region	Supply: Refinery output: Thousand barrels	Supply: Refinery output: Trillion Btu	Supply: Stock change[2]: Thousand barrels	Supply: Stock change[2]: Trillion Btu	Supply: Net shipments[3]: Thousand barrels	Supply: Net shipments[3]: Trillion Btu	Supply: Total supply available for consumption: Thousand barrels	Supply: Total supply available for consumption: Trillion Btu	Demand by major consumer sector[1]: Household and commercial: Thousand barrels	Demand by major consumer sector[1]: Household and commercial: Trillion Btu	Demand by major consumer sector[1]: Industrial: Thousand barrels	Demand by major consumer sector[1]: Industrial: Trillion Btu	Demand by major consumer sector[1]: Transportation: Thousand barrels	Demand by major consumer sector[1]: Transportation: Trillion Btu	Demand by major consumer sector[1]: Total domestic demand: Thousand barrels	Demand by major consumer sector[1]: Total domestic demand: Trillion Btu
United States total.	135,772.0	779.2	-4,550.0	-25.5	+1,232.0	+8.4	132,454.0	762.1	79,012.0	447.9	20,142.0	114.0	33,300.0	200.2	132,454.0	762.1
Region I:																
Subregion Ia:																
Maine..........	-	-	+3.0	Neg.	+2,289.0	+13.0	2,292.0	13.0	2,218.0	12.6	72.0	.4	2.0	Neg.	2,292.0	13.0
New Hampshire...	-	-	+2.0	Neg.	+839.0	+4.8	841.0	4.8	831.0	4.7	10.0	.1	-	-	841.0	4.8
Vermont.........	-	-	+3.0	Neg.	+815.0	+4.7	818.0	4.7	803.0	4.6	14.0	.1	1.0	Neg.	818.0	4.7
Massachusetts...	679.0	4.2	-33.0	-.2	+5,784.0	+32.8	6,430.0	36.8	5,409.0	30.7	298.0	1.7	723.0	4.4	6,430.0	36.8
Rhode Island....	-	-	-	-	+884.0	+5.0	884.0	5.0	869.0	4.9	15.0	.1	-	-	884.0	5.0
Connecticut.....	-	-	+3.0	Neg.	+2,690.0	+15.5	2,693.0	15.5	1,624.0	9.2	286.0	1.6	783.0	4.7	2,693.0	15.5
New York........	1,109.0	8.7	-20.0	-.1	+11,009.0	+62.4	12,098.0	71.0	4,833.0	27.4	459.0	2.6	6,806.0	41.0	12,098.0	71.0
New Jersey......	5,783.0	33.0	-354.0	-2.0	-2,515.0	-14.3	2,914.0	16.7	2,109.0	12.0	354.0	2.0	451.0	2.7	2,914.0	16.7
Pennsylvania....	5,228.0	30.0	-1,043.0	-5.9	+39.0	+.2	4,224.0	24.3	3,134.0	17.8	367.0	2.1	723.0	4.4	4,224.0	24.3
Delaware........	1,314.0	7.3	-75.0	-.4	-273.0	-1.5	966.0	5.4	922.0	5.2	42.0	.2	2.0	Neg.	966.0	5.4
Maryland........	-	-	-10.0	-.1	+2,987.0	+17.1	2,977.0	17.0	2,327.0	13.2	113.0	.6	537.0	3.2	2,977.0	17.0
District of Columbia.......	-	-	-	-	+161.0	+1.0	161.0	1.0	134.0	.8	27.0	.2	-	-	161.0	1.0
Virginia........	-	-	+5.0	Neg.	+5,843.0	+33.3	5,848.0	33.3	4,844.0	27.4	185.0	1.0	819.0	4.9	5,848.0	33.3
West Virginia...	68.0	.3	-3.0	Neg.	+227.0	+1.3	292.0	1.6	163.0	.9	112.0	.6	17.0	.1	292.0	1.6
North Carolina..	-	-	+13.0	+.1	+12,158.0	+68.8	12,171.0	68.9	10,825.0	61.3	1,243.0	7.0	103.0	.6	12,171.0	68.9
South Carolina..	-	-	+7.0	Neg.	+4,527.0	+25.7	4,534.0	25.7	3,718.0	21.1	762.0	4.3	54.0	.3	4,534.0	25.7
Georgia.........	-	-	+10.0	+.1	+1,698.0	+9.7	1,708.0	9.8	1,001.0	5.7	550.0	3.1	157.0	1.0	1,708.0	9.8
Florida.........	-	-	+10.0	+.1	+6,285.0	+36.4	6,295.0	36.5	3,360.0	19.1	595.0	3.4	2,340.0	14.0	6,295.0	36.5
Kentucky........	1,679.0	9.4	+31.0	+.2	-34.0	-.2	1,676.0	9.4	1,207.0	6.8	375.0	2.1	94.0	.5	1,676.0	9.4
Tennessee.......	93.0	.6	+9.0	+.1	+2,681.0	+15.2	2,783.0	15.9	1,287.0	7.3	1,332.0	7.6	164.0	1.0	2,783.0	15.9
Alabama.........	-	-	+7.0	Neg.	+1,098.0	+6.2	1,105.0	6.2	595.0	3.4	449.0	2.5	61.0	.3	1,105.0	6.2
Mississippi.....	30.0	.2	+9.0	+.1	+358.0	+2.0	397.0	2.3	68.0	.4	329.0	1.9	-	-	397.0	2.3
Ohio............	5,225.0	29.8	-233.0	-1.3	-551.0	-3.1	4,441.0	25.4	2,768.0	15.7	1,180.0	6.7	493.0	3.0	4,441.0	25.4
Subtotal Ia...	21,208.0	123.5	-1,659.0	-9.3	+58,999.0	+336.0	78,548.0	450.2	55,049.0	312.2	9,169.0	51.9	14,330.0	86.1	78,548.0	450.2
Subregion Ib:																
Indiana.........	7,043.0	41.0	-173.0	-1.0	-469.0	-2.7	6,401.0	37.3	3,785.0	21.5	107.0	.6	2,509.0	15.2	6,401.0	37.3
Illinois........	12,442.0	71.0	-431.0	-2.4	-5,329.0	-30.2	6,682.0	38.4	3,563.0	20.2	1,796.0	10.2	1,323.0	8.0	6,682.0	38.4
Michigan........	2,568.0	14.8	+141.0	+.8	+2,086.0	+11.8	4,795.0	27.4	2,790.0	15.8	1,274.0	7.2	731.0	4.4	4,795.0	27.4
Wisconsin.......	42.0	.2	+16.0	+.1	+2,993.0	+17.0	3,051.0	17.3	2,168.0	12.3	790.0	4.5	93.0	.5	3,051.0	17.3
Subtotal Ib...	22,095.0	127.0	-447.0	-2.5	-719.0	-4.1	20,929.0	120.4	12,306.0	69.8	3,967.0	22.5	4,656.0	28.1	20,929.0	120.4
Subtotal I..	43,303.0	250.5	-2,106.0	-11.8	+58,280.0	+331.9	99,477.0	570.6	67,355.0	382.0	13,136.0	74.4	18,986.0	114.2	99,477.0	570.6
Region II:																
Subregion IIa:																
Minnesota.......	409.0	2.5	+23.0	+.1	+2,366.0	+13.4	2,798.0	16.0	2,320.0	13.2	245.0	1.4	233.0	1.4	2,798.0	16.0
Iowa............	-	-	+17.0	+.1	+2,565.0	+14.6	2,582.0	14.7	2,390.0	13.6	192.0	1.1	-	-	2,582.0	14.7
Missouri........	1,376.0	8.0	+9.0	+.1	+1,570.0	+8.9	2,955.0	17.0	1,802.0	10.2	281.0	1.6	872.0	5.2	2,955.0	17.0
North Dakota....	1,507.0	8.6	-46.0	-.3	-559.0	-3.2	902.0	5.1	858.0	4.9	44.0	.2	-	-	902.0	5.1
South Dakota....	-	-	-3.0	Neg.	+976.0	+5.5	973.0	5.5	901.0	5.1	72.0	.4	-	-	973.0	5.5
Nebraska........	8.0	Neg.	+9.0	+.1	+680.0	+3.8	697.0	3.9	479.0	2.7	197.0	1.1	21.0	.1	697.0	3.9
Subtotal IIa..	3,300.0	19.1	+9.0	+.1	+7,598.0	+43.0	10,907.0	62.2	8,750.0	49.7	1,031.0	5.8	1,126.0	6.7	10,907.0	62.2
Subregion IIb:																
Arkansas........	1,955.0	11.1	-141.0	-.8	-1,250.0	-7.1	564.0	3.2	209.0	1.2	355.0	2.0	-	-	564.0	3.2
Louisiana.......	22,265.0	126.4	-681.0	-3.9	-20,089.0	-113.9	1,495.0	8.6	235.0	1.3	690.0	3.9	570.0	3.4	1,495.0	8.6
Oklahoma........	1,325.0	7.5	+5.0	Neg.	-824.0	-4.7	506.0	2.8	199.0	1.1	231.0	1.3	76.0	.4	506.0	2.8
Texas...........	47,847.0	272.0	-605.0	-3.4	-41,933.0	-237.8	5,309.0	30.8	743.0	4.2	2,642.0	15.0	1,924.0	11.6	5,309.0	30.8
New Mexico......	120.0	.7	+20.0	+.1	+411.0	+2.3	551.0	3.1	235.0	1.3	249.0	1.4	67.0	.4	551.0	3.1
Kansas..........	2,446.0	13.8	-3.0	Neg.	-1,745.0	-9.9	698.0	3.9	395.0	2.2	300.0	1.7	3.0	Neg.	698.0	3.9
Subtotal IIb..	75,958.0	431.5	-1,405.0	-8.0	-65,430.0	-371.1	9,123.0	52.4	2,016.0	11.3	4,467.0	25.3	2,640.0	15.8	9,123.0	52.4
Subtotal II.	79,258.0	450.6	-1,396.0	-7.9	-57,832.0	-328.1	20,030.0	114.6	10,766.0	61.0	5,498.0	31.1	3,766.0	22.5	20,030.0	114.6
Region III:																
Subregion IIIa:																
Montana.........	431.0	2.5	+23.0	+.1	+42.0	+.2	496.0	2.8	465.0	2.6	11.0	.1	20.0	.1	496.0	2.8
Idaho...........	-	-	-12.0	-.1	+153.0	+.9	141.0	.8	102.0	.6	5.0	Neg.	34.0	.2	141.0	.8
Wyoming.........	360.0	1.9	-25.0	-.1	-237.0	-1.3	98.0	.5	43.0	.2	48.0	.3	7.0	-	98.0	.5
Utah............	111.0	.6	-8.0	Neg.	+7.0	Neg.	110.0	.6	16.0	.1	20.0	.1	74.0	.4	110.0	.6
Colorado........	267.0	1.7	-40.0	-.2	+751.0	+4.3	978.0	5.8	165.0	.9	111.0	.6	702.0	4.3	978.0	5.8
Washington......	1,204.0	7.0	-60.0	-.3	-287.0	-1.6	857.0	5.1	-	-	105.0	.6	752.0	4.5	857.0	5.1
Oregon..........	Neg.	Neg.	-73.0	-.4	+302.0	+1.7	229.0	1.3	1.0	Neg.	44.0	.2	184.0	1.1	229.0	1.3
Subtotal IIIa.	2,373.0	13.7	-195.0	-1.0	+731.0	+4.2	2,909.0	16.9	792.0	4.4	344.0	1.9	1,773.0	10.6	2,909.0	16.9
Subregion IIIb:																
Arizona.........	-	-	-37.0	-.2	+224.0	+1.3	187.0	1.1	-	-	64.0	.4	123.0	.7	187.0	1.1
Nevada..........	-	-	-17.0	-.1	+74.0	+.4	57.0	.3	-	-	3.0	Neg.	54.0	.3	57.0	.3
California......	10,778.0	63.7	-728.0	-4.1	-1,861.0	-10.6	8,189.0	49.0	76.0	.4	939.0	5.3	7,174.0	43.3	8,189.0	49.0
Subtotal IIIb.	10,778.0	63.7	-782.0	-4.4	-1,563.0	-8.9	8,433.0	50.4	76.0	.4	1,006.0	5.7	7,351.0	44.3	8,433.0	50.4
Subregion IIIc:																
Alaska..........	-	-	-17.0	-.1	+300.0	+1.8	283.0	1.7	-	-	90.0	.5	193.0	1.2	283.0	1.7
Hawaii..........	60.0	.7	-54.0	-.3	+1,316.0	+7.5	1,322.0	7.9	23.0	.1	68.0	.4	1,231.0	7.4	1,322.0	7.9
Subtotal IIIc	60.0	.7	-71.0	-.4	+1,616.0	+9.3	1,605.0	9.6	23.0	.1	158.0	.9	1,424.0	8.6	1,605.0	9.6
Subtotal III	13,211.0	78.1	-1,048.0	-5.8	+784.0	+4.6	12,947.0	76.9	891.0	4.9	1,508.0	8.5	10,548.0	63.5	12,947.0	76.9

Neg.--Negligible.
[1]Electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.
[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.
[3]Includes net shipments: -601.0 thousand barrels; -3.4 trillion Btu.

TABLE 9. - Supply and demand for distillate fuel oil by major consumer sector, by States and Regions

1960

State and Region	Supply: Refinery output, Thousand barrels	Supply: Refinery output, Trillion Btu	Supply: Stock change[1], Thousand barrels	Supply: Stock change[1], Trillion Btu	Supply: Net shipments[2], Thousand barrels	Supply: Net shipments[2], Trillion Btu	Supply: Total supply available for consumption, Thousand barrels	Supply: Total supply available for consumption, Trillion Btu	Demand: Household and commercial, Thousand barrels	Demand: Household and commercial, Trillion Btu	Demand: Industrial, Thousand barrels	Demand: Industrial, Trillion Btu	Demand: Transportation, Thousand barrels	Demand: Transportation, Trillion Btu	Demand: Electricity generation, utilities, Thousand barrels	Demand: Electricity generation, utilities, Trillion Btu	Demand: Miscellaneous and unaccounted for, Thousand barrels	Demand: Miscellaneous and unaccounted for, Trillion Btu	Total domestic demand, Thousand barrels	Total domestic demand, Trillion Btu
United States total.	667,050.0	3,885.5	+12,709.0	+73.8	+3,566.0	+20.9	683,325.0	3,980.2	438,010.0	2,551.4	46,218.0	269.1	148,880.0	867.3	4,742.0	27.4	45,475.0	265.0	683,325.0	3,980.2
Region I:																				
Subregion Ia:																				
Maine	-	-	+93.0	+.5	+7,363.0	+42.9	7,456.0	43.4	5,822.0	33.9	169.0	1.0	1,233.0	7.2	110.0	.6	122.0	.7	7,456.0	43.4
New Hampshire	-	-	+46.0	+.3	+4,438.0	+25.8	4,484.0	26.1	4,181.0	24.3	49.0	.3	204.0	1.2	15.0	.1	35.0	.2	4,484.0	26.1
Vermont	-	-	+46.0	+.3	+2,893.0	+16.8	2,939.0	17.1	2,567.0	14.9	67.0	.5	248.0	1.4	2.0	Neg.	55.0	.3	2,939.0	17.1
Massachusetts	3,838.0	22.4	+281.0	+1.6	+46,903.0	+273.1	51,022.0	297.1	47,441.0	276.2	800.0	4.7	2,299.0	13.4	273.0	1.6	209.0	1.2	51,022.0	297.1
Rhode Island	787.0	4.6	-929.0	-5.4	+8,235.0	+47.9	8,093.0	47.1	6,933.0	40.3	303.0	1.8	810.0	4.7	34.0	.2	13.0	.1	8,093.0	47.1
Connecticut	-	-	+93.0	+.5	+23,137.0	+134.8	23,230.0	135.3	21,130.0	123.1	921.0	5.3	1,040.0	6.1	38.0	.2	101.0	.6	23,230.0	135.3
New York	5,914.0	34.4	+571.0	+3.3	+75,192.0	+437.9	81,677.0	475.6	67,937.0	395.5	3,549.0	20.8	8,445.0	49.1	181.0	1.1	1,565.0	9.1	81,677.0	475.6
New Jersey	45,842.0	267.1	+1,826.0	+10.6	-2,126.0	-12.4	45,542.0	265.3	38,615.0	225.0	1,704.0	9.9	4,595.0	26.8	40.0	.2	588.0	3.4	45,542.0	265.3
Pennsylvania	53,826.0	313.5	+392.0	+2.3	-8,550.0	-49.8	45,668.0	266.0	32,966.0	192.2	4,361.0	25.3	7,291.0	42.4	88.0	.5	962.0	5.6	45,668.0	266.0
Delaware	11,775.0	68.6	+640.0	+3.7	-9,692.0	-56.4	2,723.0	15.9	2,318.0	13.5	203.0	1.2	149.0	.9	30.0	.2	23.0	.1	2,723.0	15.9
Maryland	1,026.0	6.0	+1,112.0	+6.5	+10,963.0	+63.8	13,101.0	76.3	9,726.0	56.7	344.0	1.9	2,315.0	13.5	301.0	1.8	415.0	2.4	13,101.0	76.3
District of Columbia	-	-	-	-	+2,914.0	+17.0	2,914.0	17.0	2,463.0	14.4	8.0	Neg.	303.0	1.8	36.0	.2	104.0	.6	2,914.0	17.0
Virginia	4,231.0	24.6	+300.0	+1.7	+9,653.0	+56.3	14,184.0	82.6	8,634.0	50.3	879.0	5.1	4,014.0	23.4	103.0	.6	554.0	3.2	14,184.0	82.6
West Virginia	554.0	3.2	+100.0	+.6	+1,808.0	+10.5	2,462.0	14.3	405.0	2.3	275.0	1.6	1,714.0	10.0	-	-	68.0	.4	2,462.0	14.3
North Carolina	-	-	+418.0	+2.4	+12,935.0	+75.4	13,353.0	77.8	8,943.0	52.1	596.0	3.5	3,128.0	18.2	24.0	.1	662.0	3.9	13,353.0	77.8
South Carolina	418.0	2.4	+224.0	+1.3	+4,561.0	+26.6	5,203.0	30.3	3,110.0	18.1	253.0	1.5	1,171.0	6.8	-	-	669.0	3.9	5,203.0	30.3
Georgia	127.0	.7	+299.0	+1.7	+4,691.0	+27.4	5,117.0	29.8	1,205.0	7.1	468.0	2.7	2,545.0	14.8	-	-	899.0	5.2	5,117.0	29.8
Florida	213.0	1.2	+332.0	+1.9	+8,426.0	+49.2	8,971.0	52.3	2,404.0	13.8	607.0	3.6	3,795.0	22.1	576.0	3.5	1,589.0	9.3	8,971.0	52.3
Kentucky	6,446.0	37.6	+245.0	+1.4	-1,858.0	-10.8	4,833.0	28.2	1,147.0	6.7	588.0	3.5	2,492.0	14.5	4.0	Neg.	602.0	3.5	4,833.0	28.2
Tennessee	1,402.0	8.2	+246.0	+1.4	+3,620.0	+21.1	5,268.0	30.7	746.0	4.4	522.0	3.0	2,861.0	16.7	-	-	1,139.0	6.6	5,268.0	30.7
Alabama	346.0	2.0	-13.0	-.1	+5,037.0	+29.4	5,370.0	31.3	421.0	2.5	1,380.0	8.0	2,464.0	14.4	-	-	1,105.0	6.4	5,370.0	31.3
Mississippi	1,145.0	6.7	-58.0	-.3	+1,277.0	+7.4	2,364.0	13.8	49.0	.3	385.0	2.3	848.0	4.9	-	-	1,082.0	6.3	2,364.0	13.8
Ohio	23,890.0	139.1	+879.0	+5.1	-933.0	-5.4	23,836.0	138.8	12,065.0	70.3	2,550.0	14.8	7,754.0	45.2	124.0	.7	1,343.0	7.8	23,836.0	138.8
Subtotal Ia	161,780.0	942.3	+7,143.0	+41.3	+210,887.0	+1,228.5	379,810.0	2,212.1	281,228.0	1,637.9	20,981.0	122.3	61,718.0	359.5	1,979.0	11.6	13,904.0	80.8	379,810.0	2,212.1
Subregion Ib:																				
Indiana	36,499.0	212.6	+464.0	+2.7	-11,367.0	-66.2	25,596.0	149.1	17,460.0	101.8	3,191.0	18.6	3,832.0	22.3	126.0	.7	987.0	5.7	25,596.0	149.1
Illinois	40,234.0	234.4	-566.0	-3.3	+2,822.0	+16.4	42,490.0	247.5	29,987.0	174.5	1,733.0	10.1	8,549.0	49.8	237.0	1.4	1,984.0	11.7	42,490.0	247.5
Michigan	13,136.0	76.5	+251.0	+1.5	+17,077.0	+99.5	30,464.0	177.5	25,409.0	147.9	1,096.0	6.4	2,380.0	13.9	433.0	2.6	1,146.0	6.7	30,464.0	177.5
Wisconsin	1,194.0	7.0	-140.0	-.8	+20,657.0	+120.3	21,711.0	126.5	17,156.0	100.0	2,187.0	12.7	1,595.0	9.3	57.0	.3	716.0	4.2	21,711.0	126.5
Subtotal Ib	91,063.0	530.5	+9.0	+.1	+29,189.0	+170.0	120,261.0	700.6	90,012.0	524.2	8,207.0	47.8	16,356.0	95.3	853.0	5.0	4,833.0	28.3	120,261.0	700.6
Subtotal I	252,843.0	1,472.8	+7,152.0	+41.4	+240,076.0	+1,398.5	500,071.0	2,912.7	371,240.0	2,162.1	29,188.0	170.1	78,074.0	454.8	2,832.0	16.6	18,737.0	109.1	500,071.0	2,912.7
Region II:																				
Subregion IIa:																				
Minnesota	5,232.0	30.5	+37.0	+.2	+10,972.0	+63.9	16,241.0	94.6	10,792.0	63.0	900.0	5.2	3,111.0	18.1	314.0	1.8	1,124.0	6.5	16,241.0	94.6
Iowa	-	-	-	-	+11,141.0	+64.9	11,141.0	64.9	8,126.0	47.4	196.0	1.2	1,689.0	9.8	283.0	1.6	847.0	4.9	11,141.0	64.9
Missouri	4,997.0	29.1	+65.0	+.4	+7,768.0	+45.2	12,830.0	74.7	6,271.0	36.5	607.0	3.6	4,419.0	25.7	245.0	1.4	1,288.0	7.5	12,830.0	74.7
North Dakota	4,213.0	24.5	+32.0	+.2	-470.0	-2.7	3,775.0	22.0	2,345.0	13.8	42.0	.2	587.0	3.4	22.0	.1	779.0	4.5	3,775.0	22.0
South Dakota	-	-	-48.0	-.3	+3,012.0	+17.6	2,964.0	17.3	2,095.0	12.3	25.0	.1	358.0	2.1	42.0	.2	444.0	2.6	2,964.0	17.3
Nebraska	210.0	1.2	-20.0	-.1	+3,993.0	+23.3	4,183.0	24.4	1,876.0	10.9	36.0	.2	1,393.0	8.1	113.0	.7	765.0	4.5	4,183.0	24.4
Subtotal IIa	14,652.0	85.3	+66.0	+.4	+36,416.0	+212.2	51,134.0	297.9	31,505.0	183.9	1,806.0	10.5	11,557.0	67.2	1,019.0	5.8	5,247.0	30.5	51,134.0	297.9
Subregion IIb:																				
Arkansas	6,300.0	36.7	-59.0	-.3	-4,189.0	-24.4	2,052.0	12.0	140.0	.8	124.0	.8	912.0	5.3	41.0	.2	835.0	4.9	2,052.0	12.0
Louisiana	53,497.0	311.7	+418.0	+2.4	-43,221.0	-251.8	10,694.0	62.3	1,401.0	8.1	2,058.0	11.9	5,506.0	32.2	51.0	.3	1,678.0	9.8	10,694.0	62.3
Oklahoma	32,870.0	191.4	-137.0	-.8	-30,102.0	-175.3	2,631.0	15.3	375.0	2.1	205.0	1.2	1,303.0	7.6	50.0	.3	698.0	4.1	2,631.0	15.3
Texas	185,901.0	1,082.8	+4,509.0	+26.3	-166,095.0	-967.5	24,315.0	141.6	1,925.0	11.2	4,161.0	24.1	13,187.0	76.8	36.0	.2	5,006.0	29.3	24,315.0	141.6
New Mexico	1,521.0	8.9	+22.0	+.1	+1,522.0	+8.9	3,065.0	17.9	502.0	3.1	322.0	1.8	1,886.0	11.0	21.0	.1	334.0	1.9	3,065.0	17.9
Kansas	27,043.0	157.6	+224.0	+1.3	-22,516.0	-131.2	4,751.0	27.7	670.0	3.9	158.0	.9	3,031.0	17.7	141.0	.8	751.0	4.4	4,751.0	27.7
Subtotal IIb	307,132.0	1,789.1	+4,977.0	+29.0	-264,601.0	-1,541.3	47,508.0	276.8	5,013.0	29.2	7,028.0	40.7	25,825.0	150.6	340.0	1.9	9,302.0	54.4	47,508.0	276.8
Subtotal II	321,784.0	1,874.4	+5,043.0	+29.4	-228,185.0	-1,329.1	98,642.0	574.7	36,518.0	213.1	8,834.0	51.2	37,382.0	217.8	1,359.0	7.7	14,549.0	84.9	98,642.0	574.7
Region III:																				
Subregion IIIa:																				
Montana	5,218.0	30.4	+344.0	+2.0	-685.0	-4.0	4,877.0	28.4	1,066.0	6.2	160.0	.9	2,815.0	16.4	-	-	836.0	4.9	4,877.0	28.4
Idaho	-	-	-3.0	Neg.	+4,058.0	+23.6	4,055.0	23.6	2,457.0	14.3	344.0	2.0	618.0	3.6	-	-	636.0	3.7	4,055.0	23.6
Wyoming	7,227.0	42.1	+72.0	+.4	-4,041.0	-23.5	3,258.0	19.0	178.0	1.0	722.0	4.3	1,737.0	10.1	-	-	621.0	3.6	3,258.0	19.0
Utah	8,659.0	50.4	-107.0	-.6	-4,711.0	-27.4	3,841.0	22.4	851.0	5.0	218.0	1.3	2,285.0	13.3	93.0	.5	394.0	2.3	3,841.0	22.4
Colorado	2,774.0	16.2	-112.0	-.7	+1,563.0	+9.1	4,225.0	24.6	996.0	5.8	360.0	2.1	2,109.0	12.3	58.0	.3	702.0	4.1	4,225.0	24.6
Washington	6,855.0	39.9	+12.0	+.1	+11,178.0	+65.1	18,045.0	105.1	12,949.0	75.4	777.0	4.5	2,503.0	14.6	-	-	1,816.0	10.6	18,045.0	105.1
Oregon	Neg.	Neg.	-26.0	-.2	+10,946.0	+63.8	10,920.0	63.6	5,922.0	34.5	989.0	5.8	2,803.0	16.3	-	-	1,206.0	7.0	10,920.0	63.6
Subtotal IIIa	30,733.0	179.0	+180.0	+1.0	+18,308.0	+106.7	49,221.0	286.7	24,419.0	142.2	3,570.0	20.9	14,870.0	86.6	151.0	.8	6,211.0	36.2	49,221.0	286.7
Subregion IIIb:																				
Arizona	-	-	-13.0	-.1	+2,787.0	+16.3	2,774.0	16.2	229.0	1.3	534.0	3.2	1,356.0	7.9	1.0	Neg.	654.0	3.8	2,774.0	16.2
Nevada	-	-	-5.0	Neg.	+2,433.0	+14.1	2,428.0	14.1	514.0	3.0	165.0	1.0	1,482.0	8.6	36.0	.2	231.0	1.3	2,428.0	14.1
California	61,348.0	357.3	+354.0	+2.1	-35,005.0	-203.9	26,697.0	155.5	3,431.0	20.0	3,678.0	21.3	14,963.0	87.2	246.0	1.4	4,379.0	25.6	26,697.0	155.5
Subtotal IIIb	61,348.0	357.3	+336.0	+2.0	-29,785.0	-173.5	31,899.0	185.8	4,174.0	24.3	4,377.0	25.5	17,801.0	103.7	283.0	1.6	5,264.0	30.7	31,899.0	185.8
Subregion IIIc:																				
Alaska	-	-	-3.0	Neg.	+2,619.0	+15.2	2,616.0	15.2	1,588.0	9.2	169.0	1.0	513.0	3.0	86.0	.5	260.0	1.5	2,616.0	15.2
Hawaii	342.0	2.0	+1.0	Neg.	+533.0	+3.1	876.0	5.1	71.0	.5	80.0	.4	240.0	1.4	31.0	.2	454.0	2.6	876.0	5.1
Subtotal IIIc	342.0	2.0	-2.0	Neg.	+3,152.0	+18.3	3,492.0	20.3	1,659.0	9.7	249.0	1.4	753.0	4.4	117.0	.7	714.0	4.1	3,492.0	20.3
Subtotal III	92,423.0	538.3	+514.0	+3.0	-8,325.0	-48.5	84,612.0	492.8	30,252.0	176.2	8,196.0	47.8	33,424.0	194.7	551.0	3.1	12,189.0	71.0	84,612.0	492.8

Neg.--Negligible.

[1]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[2]Includes net foreign trade: 3,319.0 thousand barrels; 19.3 trillion Btu.

TABLE 10. - Supply and demand for residual fuel oil by major consumer sector, by States and Regions

1960

State and Region	Supply: Refinery output, Thousand barrels	Supply: Refinery output, Trillion Btu	Supply: Stock change[1], Thousand barrels	Supply: Stock change[1], Trillion Btu	Supply: Net shipments[2], Thousand barrels	Supply: Net shipments[2], Trillion Btu	Supply: Total supply available for consumption, Thousand barrels	Supply: Total supply available for consumption, Trillion Btu	Demand: Household and commercial, Thousand barrels	Demand: Household and commercial, Trillion Btu	Demand: Industrial, Thousand barrels	Demand: Industrial, Trillion Btu	Demand: Transportation, Thousand barrels	Demand: Transportation, Trillion Btu	Demand: Electricity generation, utilities, Thousand barrels	Demand: Electricity generation, utilities, Trillion Btu	Demand: Miscellaneous and unaccounted for, Thousand barrels	Demand: Miscellaneous and unaccounted for, Trillion Btu	Total domestic demand, Thousand barrels	Total domestic demand, Trillion Btu
United States total	332,147.0	2,088.1	+8,391.0	+52.6	+209,998.0	+1,320.3	550,536.0	3,461.0	125,088.0	786.5	202,331.0	1,271.9	131,418.0	826.1	85,408.0	536.9	6,291.0	39.6	550,536.0	3,461.0
Region I:																				
Subregion Ia:																				
Maine	-	-	+11.0	+.1	+5,731.0	+36.0	5,742.0	36.1	1,179.0	7.4	1,467.0	9.2	760.0	4.8	2,256.0	14.2	80.0	.5	5,742.0	36.1
New Hampshire	-	-	+6.0	Neg.	+2,318.0	+14.6	2,324.0	14.6	196.0	1.3	529.0	3.3	48.0	.3	1,547.0	9.7	4.0	Neg.	2,324.0	14.6
Vermont	-	-	+6.0	Neg.	+492.0	+3.1	498.0	3.1	141.0	.9	326.0	2.0	-	-	31.0	.2	-	-	498.0	3.1
Massachusetts	879.0	5.5	+82.0	+.5	+37,981.0	+238.8	38,942.0	244.8	16,183.0	101.6	11,100.0	69.9	1,182.0	7.4	10,433.0	65.6	44.0	.3	38,942.0	244.8
Rhode Island	140.0	.9	-151.0	-.9	+9,513.0	+59.7	9,502.0	59.7	2,524.0	15.9	2,636.0	16.5	3,746.0	23.6	579.0	3.6	17.0	.1	9,502.0	59.7
Connecticut	-	-	+11.0	+.1	+14,439.0	+90.7	14,450.0	90.8	3,981.0	25.0	8,571.0	53.8	200.0	1.3	1,698.0	10.7	-	-	14,450.0	90.8
New York	4,079.0	25.6	-36.0	-.2	+72,543.0	+456.1	76,586.0	481.5	38,084.0	239.5	11,379.0	71.5	16,703.0	104.9	10,291.0	64.8	129.0	.8	76,586.0	481.5
New Jersey	23,188.0	145.8	+2.0	Neg.	+19,601.0	+123.2	42,791.0	269.0	4,079.0	25.6	21,263.0	133.8	5,634.0	35.3	11,761.0	74.0	54.0	.3	42,791.0	269.0
Pennsylvania	27,273.0	171.5	+334.0	+2.1	+15,124.0	+95.0	42,731.0	268.6	9,939.0	62.5	24,122.0	151.6	4,900.0	30.8	3,361.0	21.1	409.0	2.6	42,731.0	268.6
Delaware	3,252.0	20.4	+50.0	+.3	+2,779.0	+17.5	6,081.0	38.2	726.0	4.6	3,407.0	21.4	1,433.0	9.0	4.0	Neg.	511.0	3.2	6,081.0	38.2
Maryland	73.0	.5	+146.0	+.9	+16,271.0	+102.3	16,490.0	103.7	4,486.0	28.1	7,992.0	50.3	3,812.0	24.0	170.0	1.1	30.0	.2	16,490.0	103.7
District of Columbia	-	-	-	-	+2,387.0	+15.0	2,387.0	15.0	2,205.0	13.8	128.0	.8	27.0	.2	18.0	.1	9.0	.1	2,387.0	15.0
Virginia	499.0	3.1	+39.0	+.2	+16,910.0	+106.4	17,448.0	109.7	2,975.0	18.8	2,688.0	16.9	11,534.0	72.4	123.0	.8	128.0	.8	17,448.0	109.7
West Virginia	67.0	.4	+16.0	+.1	+1,368.0	+8.6	1,451.0	9.1	96.0	.6	1,319.0	8.3	3.0	Neg.	33.0	.2	-	-	1,451.0	9.1
North Carolina	-	-	+50.0	+.3	+4,487.0	+28.2	4,537.0	28.5	734.0	4.6	3,037.0	19.1	484.0	3.0	49.0	.3	233.0	1.5	4,537.0	28.5
South Carolina	5.0	Neg.	+34.0	+.2	+4,595.0	+28.9	4,634.0	29.1	597.0	3.8	2,551.0	15.9	1,115.0	7.0	25.0	.2	346.0	2.2	4,634.0	29.1
Georgia	75.0	.5	+40.0	+.3	+6,298.0	+39.5	6,413.0	40.3	72.0	.5	4,605.0	29.0	1,512.0	9.4	37.0	.2	187.0	1.2	6,413.0	40.3
Florida	-	-	+39.0	+.2	+28,939.0	+181.9	28,978.0	182.1	979.0	6.3	10,849.0	68.0	3,691.0	23.3	12,550.0	78.9	909.0	5.6	28,978.0	182.1
Kentucky	3,597.0	22.6	+7.0	Neg.	-3,283.0	-20.6	321.0	2.0	15.0	.1	270.0	1.7	34.0	.2	-	-	2.0	Neg.	321.0	2.0
Tennessee	736.0	4.6	-3.0	Neg.	-549.0	-3.4	184.0	1.2	24.0	.2	141.0	.9	8.0	Neg.	-	-	11.0	.1	184.0	1.2
Alabama	509.0	3.2	+59.0	+.4	+3,634.0	+22.8	4,202.0	26.4	142.0	.9	1,758.0	11.0	2,230.0	14.0	-	-	72.0	.5	4,202.0	26.4
Mississippi	145.0	.9	+30.0	+.2	+164.0	+1.0	339.0	2.1	4.0	Neg.	223.0	1.4	11.0	.1	97.0	.6	4.0	Neg.	339.0	2.1
Ohio	11,860.0	74.6	+133.0	+.8	-611.0	-3.8	11,382.0	71.6	642.0	4.0	10,310.0	64.9	304.0	1.9	112.0	.7	14.0	.1	11,382.0	71.6
Subtotal Ia	76,377.0	480.1	+905.0	+5.6	+261,131.0	+1,641.5	338,413.0	2,127.2	90,003.0	566.0	130,671.0	821.2	59,371.0	372.9	55,175.0	347.0	3,193.0	20.1	338,413.0	2,127.2
Subregion Ib:																				
Indiana	24,745.0	155.6	-297.0	-1.9	-11,563.0	-72.7	12,885.0	81.0	1,973.0	12.3	10,345.0	65.0	343.0	2.2	183.0	1.2	41.0	.3	12,885.0	81.0
Illinois	15,069.0	94.7	-360.0	-2.3	+11,184.0	+70.3	25,893.0	162.7	12,501.0	78.5	12,046.0	75.7	1,144.0	7.2	105.0	.7	97.0	.6	25,893.0	162.7
Michigan	8,847.0	55.6	+166.0	+1.0	+2,229.0	+14.1	11,242.0	70.7	2,772.0	17.4	7,691.0	48.4	713.0	4.5	5.0	Neg.	61.0	.4	11,242.0	70.7
Wisconsin	2,000.0	12.6	+60.0	+.4	+2,215.0	+13.9	4,275.0	26.9	1,886.0	11.9	1,972.0	12.4	370.0	2.3	17.0	.1	30.0	.2	4,275.0	26.9
Subtotal Ib	50,661.0	318.5	-431.0	-2.8	+4,065.0	+25.6	54,295.0	341.3	19,132.0	120.1	32,054.0	201.5	2,570.0	16.2	310.0	2.0	229.0	1.5	54,295.0	341.3
Subtotal I	127,038.0	798.6	+474.0	+2.8	+265,196.0	+1,667.1	392,708.0	2,468.5	109,135.0	686.1	162,725.0	1,022.7	61,941.0	389.1	55,485.0	349.0	3,422.0	21.6	392,708.0	2,468.5
Region II:																				
Subregion IIa:																				
Minnesota	3,960.0	24.9	+147.0	+.9	+2,256.0	+14.2	6,363.0	40.0	1,311.0	8.3	4,869.0	30.6	93.0	.5	78.0	.5	12.0	.1	6,363.0	40.0
Iowa	-	-	-	-	+1,021.0	+6.4	1,021.0	6.4	383.0	2.4	390.0	2.4	222.0	1.4	10.0	.1	16.0	.1	1,021.0	6.4
Missouri	835.0	5.2	-84.0	-.5	+2,275.0	+14.3	3,026.0	19.0	1,557.0	9.7	1,254.0	7.9	33.0	.2	60.0	.4	122.0	.8	3,026.0	19.0
North Dakota	572.0	3.6	-	-	+91.0	+.6	663.0	4.2	76.0	.5	514.0	3.3	68.0	.4	5.0	Neg.	-	-	663.0	4.2
South Dakota	-	-	-3.0	Neg.	+63.0	+.4	60.0	.4	31.0	.2	15.0	.1	11.0	.1	-	-	3.0	Neg.	60.0	.4
Nebraska	171.0	1.1	+2.0	Neg.	+205.0	+1.3	378.0	2.4	53.0	.3	6.0	Neg.	253.0	1.7	65.0	.4	1.0	Neg.	378.0	2.4
Subtotal IIa	5,538.0	34.8	+62.0	+.4	+5,911.0	+37.2	11,511.0	72.4	3,411.0	21.4	7,048.0	44.3	680.0	4.3	218.0	1.4	154.0	1.0	11,511.0	72.4
Subregion IIb:																				
Arkansas	1,671.0	10.5	+41.0	+.3	-1,238.0	-7.8	474.0	3.0	-	-	409.0	2.6	3.0	Neg.	62.0	.4	-	-	474.0	3.0
Louisiana	16,862.0	106.0	-375.0	-2.4	-7,888.0	-49.5	8,599.0	54.1	33.0	.2	605.0	3.8	7,778.0	49.0	49.0	.3	134.0	.8	8,599.0	54.1
Oklahoma	4,189.0	26.3	+90.0	+.6	-2,883.0	-18.1	1,396.0	8.8	16.0	.1	1,367.0	8.7	8.0	Neg.	5.0	Neg.	-	-	1,396.0	8.8
Texas	58,629.0	368.6	-162.0	-1.0	-36,365.0	-228.6	22,102.0	139.0	321.0	2.0	3,915.0	24.6	17,365.0	109.3	32.0	.2	469.0	2.9	22,102.0	139.0
New Mexico	881.0	5.5	+4.0	Neg.	-712.0	-4.4	173.0	1.1	17.0	.1	12.0	.1	24.0	.2	91.0	.5	29.0	.2	173.0	1.1
Kansas	3,291.0	20.7	-390.0	-2.5	-652.0	-4.1	2,249.0	14.1	195.0	1.3	1,733.0	10.8	186.0	1.2	133.0	.8	2.0	Neg.	2,249.0	14.1
Subtotal IIb	85,523.0	537.6	-792.0	-5.0	-49,738.0	-312.5	34,993.0	220.1	582.0	3.7	8,041.0	50.6	25,364.0	159.7	372.0	2.2	634.0	3.9	34,993.0	220.1
Subtotal II	91,061.0	572.4	-730.0	-4.6	-43,827.0	-275.3	46,504.0	292.5	3,993.0	25.1	15,089.0	94.9	26,044.0	164.0	590.0	3.6	788.0	4.9	46,504.0	292.5
Region III:																				
Subregion IIIa:																				
Montana	2,165.0	13.6	+327.0	+2.1	-470.0	-3.0	2,022.0	12.7	354.0	2.2	1,256.0	7.9	369.0	2.3	2.0	Neg.	41.0	.3	2,022.0	12.7
Idaho	-	-	-	-	+201.0	+1.3	201.0	1.3	102.0	.7	41.0	.3	51.0	.3	-	-	7.0	Neg.	201.0	1.3
Wyoming	3,604.0	22.7	-215.0	-1.4	-1,651.0	-10.4	1,738.0	10.9	330.0	2.1	434.0	2.7	931.0	5.8	31.0	.2	12.0	.1	1,738.0	10.9
Utah	3,800.0	23.9	-79.0	-.5	+1,841.0	+11.6	5,562.0	35.0	454.0	2.9	2,520.0	15.8	362.0	2.3	2,209.0	13.9	17.0	.1	5,562.0	35.0
Colorado	1,936.0	12.2	-30.0	-.2	-116.0	-.7	1,790.0	11.3	384.0	2.4	1,179.0	7.5	134.0	.8	51.0	.3	42.0	.3	1,790.0	11.3
Washington	9,229.0	58.0	+829.0	+5.2	-879.0	-5.5	9,179.0	57.7	3,453.0	21.7	3,586.0	22.6	1,671.0	10.5	88.0	.5	381.0	2.4	9,179.0	57.7
Oregon	-	-	+61.0	+.4	+5,392.0	+33.9	5,453.0	34.3	2,045.0	12.9	1,855.0	11.6	1,133.0	7.1	11.0	.1	409.0	2.6	5,453.0	34.3
Subtotal IIIa	20,734.0	130.4	+893.0	+5.6	+4,318.0	+27.2	25,945.0	163.2	7,122.0	44.9	10,871.0	68.4	4,651.0	29.1	2,392.0	15.0	909.0	5.8	25,945.0	163.2
Subregion IIIb:																				
Arizona	-	-	+29.0	+.2	+66.0	+.4	95.0	.6	5.0	Neg.	58.0	.4	17.0	.1	13.0	.1	2.0	Neg.	95.0	.6
Nevada	-	-	+11.0	+.1	+191.0	+1.2	202.0	1.3	158.0	1.0	11.0	.1	-	-	2.0	Neg.	31.0	.2	202.0	1.3
California	93,314.0	586.7	+7,702.0	+48.4	-22,242.0	-139.9	78,774.0	495.2	4,362.0	27.4	12,485.0	78.5	37,802.0	237.7	23,315.0	146.5	810.0	5.1	78,774.0	495.2
Subtotal IIIb	93,314.0	586.7	+7,742.0	+48.7	-21,985.0	-138.3	79,071.0	497.1	4,525.0	28.4	12,554.0	79.0	37,819.0	237.8	23,330.0	146.6	843.0	5.3	79,071.0	497.1
Subregion IIIc:																				
Alaska	-	-	+8.0	+.1	+687.0	+4.3	695.0	4.4	247.0	1.6	217.0	1.4	15.0	.1	2.0	Neg.	214.0	1.3	695.0	4.4
Hawaii	-	-	+4.0	Neg.	+5,609.0	+35.3	5,613.0	35.3	66.0	.4	875.0	5.5	948.0	6.0	3,609.0	22.7	115.0	.7	5,613.0	35.3
Subtotal IIIc	-	-	+12.0	+.1	+6,296.0	+39.6	6,308.0	39.7	313.0	2.0	1,092.0	6.9	963.0	6.1	3,611.0	22.7	329.0	2.0	6,308.0	39.7
Subtotal III	114,048.0	717.1	+8,647.0	+54.4	-11,371.0	-71.5	111,324.0	700.0	11,960.0	75.3	24,517.0	154.3	43,433.0	273.0	29,333.0	184.3	2,081.0	13.1	111,324.0	700.0

Neg.--Negligible.

[1] Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[2] Includes net foreign trade; 215,604.0 thousand barrels; 1,355.5 trillion Btu.

TABLE 11. - Supply and demand for liquefied gases by major consumer sector, by States and Regions

1965

State and Region	Supply: Refinery output and natural gas process-plant product, Thousand barrels	Trillion Btu	Stock change[2], Thousand barrels	Trillion Btu	Net shipments[3], Thousand barrels	Trillion Btu	Input at refineries, Thousand barrels	Trillion Btu	Total supply available for consumption, Thousand barrels	Trillion Btu	Demand by major consumer sector[1]: Household and commercial, Thousand barrels	Trillion Btu	Industrial, Thousand barrels	Trillion Btu	Transportation, Thousand barrels	Trillion Btu	Miscellaneous and unaccounted for, Thousand barrels	Trillion Btu	Total domestic demand, Thousand barrels	Trillion Btu
United States total	374,866.0	1,503.7	-364.0	-1.5	+1,079.0	+4.3	-68,297.0	-273.9	307,284.0	1,232.6	127,285.0	510.5	149,625.0	600.1	28,424.0	114.0	1,950.0	8.0	307,284.0	1,232.6
Region I:																				
Subregion Ia:																				
Maine	-	-	-	-	+534.0	+2.1	-	-	534.0	2.1	448.0	1.8	80.0	.3	6.0	Neg.	-	-	534.0	2.1
New Hampshire	-	-	-	-	+658.0	+2.6	-	-	658.0	2.6	541.0	2.2	112.0	.4	5.0	Neg.	-	-	658.0	2.6
Vermont	-	-	-	-	+451.0	+1.8	-	-	451.0	1.8	372.0	1.5	76.0	.3	3.0	Neg.	-	-	451.0	1.8
Massachusetts	-	-	-	-	+1,502.0	+6.0	-	-	1,502.0	6.0	1,089.0	4.3	322.0	1.3	76.0	.3	15.0	.1	1,502.0	6.0
Rhode Island	-	-	-	-	+223.0	+.9	-	-	223.0	.9	158.0	.6	52.0	.2	13.0	.1	-	-	223.0	.9
Connecticut	-	-	-	-	+1,318.0	+5.3	-	-	1,318.0	5.3	815.0	3.3	432.0	1.7	17.0	.1	54.0	.2	1,318.0	5.3
New York	898.0	3.6	+476.0	+1.9	+1,979.0	+7.9	-	-	3,353.0	13.4	2,651.0	10.6	567.0	2.3	132.0	.5	3.0	Neg.	3,353.0	13.4
New Jersey	4,504.0	18.1	+106.0	+.4	+344.0	+1.4	-1,169.0	-4.7	3,785.0	15.2	790.0	3.2	2,857.0	11.4	138.0	.6	Neg.	Neg.	3,785.0	15.2
Pennsylvania	4,546.0	18.2	+14.0	+.1	+99.0	+.4	-1,673.0	-6.7	2,986.0	12.0	1,587.0	6.4	1,177.0	4.7	206.0	.8	16.0	.1	2,986.0	12.0
Delaware	2,827.0	11.3	-4.0	Neg.	-2,405.0	-9.6	-	-	418.0	1.7	339.0	1.4	68.0	.3	10.0	Neg.	1.0	Neg.	418.0	1.7
Maryland	-	-	-	-	+1,410.0	+5.7	-	-	1,410.0	5.7	1,052.0	4.3	321.0	1.3	34.0	.1	3.0	Neg.	1,410.0	5.7
District of Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia	578.0	2.3	+1.0	Neg.	+1,053.0	+4.2	-	-	1,632.0	6.5	1,333.0	5.3	169.0	.7	81.0	.3	49.0	.2	1,632.0	6.5
West Virginia	8,120.0	32.6	+5.0	Neg.	+2,213.0	+8.9	-	-	10,338.0	41.5	330.0	1.3	9,996.0	40.2	12.0	Neg.	-	-	10,338.0	41.5
North Carolina	-	-	-	-	+3,774.0	+15.1	-	-	3,774.0	15.1	3,015.0	12.0	365.0	1.5	59.0	.2	335.0	1.4	3,774.0	15.1
South Carolina	-	-	-	-	+2,072.0	+8.3	-	-	2,072.0	8.3	1,670.0	6.7	324.0	1.3	43.0	.2	35.0	.1	2,072.0	8.3
Georgia	-	-	+11.0	Neg.	+4,496.0	+18.1	-	-	4,507.0	18.1	3,638.0	14.6	353.0	1.4	239.0	1.0	277.0	1.1	4,507.0	18.1
Florida	1,120.0	4.5	+33.0	+.1	+4,515.0	+18.1	-	-	5,668.0	22.7	4,818.0	19.4	378.0	1.5	461.0	1.8	11.0	Neg.	5,668.0	22.7
Kentucky	3,570.0	14.3	+144.0	+.6	+1,490.0	+6.0	-	-	5,204.0	20.9	1,876.0	7.6	3,200.0	12.8	123.0	.5	5.0	Neg.	5,204.0	20.9
Tennessee	-	-	-	-	+2,074.0	+8.3	-127.0	-.5	1,947.0	7.8	1,336.0	5.3	423.0	1.7	188.0	.8	-	-	1,947.0	7.8
Alabama	27.0	.1	+154.0	+.6	+3,241.0	+13.0	-	-	3,422.0	13.7	3,143.0	12.6	125.0	.5	149.0	.6	5.0	Neg.	3,422.0	13.7
Mississippi	794.0	3.2	+418.0	+1.7	+3,794.0	+15.1	-685.0	-2.7	4,321.0	17.3	3,371.0	13.5	94.0	.4	802.0	3.2	54.0	.2	4,321.0	17.3
Ohio	3,105.0	12.5	-264.0	-1.1	+3,866.0	+15.5	-2,532.0	-10.2	4,175.0	16.7	2,698.0	10.8	1,127.0	4.5	323.0	1.3	27.0	.1	4,175.0	16.7
Subtotal Ia	30,089.0	120.7	+1,094.0	+4.3	+38,701.0	+155.1	-6,186.0	-24.8	63,698.0	255.3	37,070.0	148.7	22,618.0	90.7	3,120.0	12.4	890.0	3.5	63,698.0	255.3
Subregion Ib:																				
Indiana	1,541.0	6.2	-31.0	-.1	+8,057.0	+32.3	-3,199.0	-12.9	6,368.0	25.5	4,697.0	18.9	1,454.0	5.8	180.0	.7	37.0	.1	6,368.0	25.5
Illinois	15,507.0	62.2	+117.0	+.5	+5,010.0	+20.1	-3,985.0	-16.0	16,649.0	66.8	7,046.0	28.3	8,464.0	33.9	1,098.0	4.4	41.0	.2	16,649.0	66.8
Michigan	3,207.0	12.9	+359.0	+1.4	+1,367.0	+5.5	-629.0	-2.5	4,304.0	17.3	2,760.0	11.1	1,412.0	5.6	116.0	.5	16.0	.1	4,304.0	17.3
Wisconsin	139.0	.6	-3.0	Neg.	+5,310.0	+21.2	-178.0	-.7	5,268.0	21.1	4,343.0	17.4	789.0	3.2	125.0	.5	11.0	Neg.	5,268.0	21.1
Subtotal Ib	20,394.0	81.9	+442.0	+1.8	+19,744.0	+79.1	-7,991.0	-32.1	32,589.0	130.7	18,846.0	75.7	12,119.0	48.5	1,519.0	6.1	105.0	.4	32,589.0	130.7
Subtotal I	50,483.0	202.6	+1,536.0	+6.1	+58,445.0	+234.2	-14,177.0	-56.9	96,287.0	386.0	55,916.0	224.4	34,737.0	139.2	4,639.0	18.5	995.0	3.9	96,287.0	386.0
Region II:																				
Subregion IIa:																				
Minnesota	632.0	2.5	+42.0	+.2	+6,322.0	+25.4	-1,068.0	-4.3	5,928.0	23.8	4,756.0	19.1	1,000.0	4.0	129.0	.5	43.0	.2	5,928.0	23.8
Iowa	-	-	+48.0	+.2	+6,200.0	+24.9	-	-	6,248.0	25.1	5,578.0	22.4	410.0	1.6	188.0	.8	72.0	.3	6,248.0	25.1
Missouri	174.0	.7	+40.0	+.2	+8,251.0	+33.1	-839.0	-3.4	7,626.0	30.6	7,222.0	29.0	239.0	1.0	162.0	.6	3.0	Neg.	7,626.0	30.6
North Dakota	2,243.0	9.0	+56.0	+.2	-578.0	-2.3	-526.0	-2.1	1,195.0	4.8	892.0	3.5	213.0	.9	77.0	.3	13.0	.1	1,195.0	4.8
South Dakota	-	-	-	-	+3,502.0	+14.0	-	-	3,502.0	14.0	1,409.0	5.7	2,006.0	8.0	84.0	.3	3.0	Neg.	3,502.0	14.0
Nebraska	403.0	1.6	+24.0	+.1	+2,982.0	+12.0	-	-	3,409.0	13.7	2,995.0	12.0	72.0	.3	340.0	1.4	2.0	Neg.	3,409.0	13.7
Subtotal IIa	3,452.0	13.8	+210.0	+.9	+26,679.0	+107.1	-2,433.0	-9.8	27,908.0	112.0	22,852.0	91.7	3,940.0	15.8	980.0	3.9	136.0	.6	27,908.0	112.0
Subregion IIb:																				
Arkansas	2,145.0	8.6	+78.0	+.3	+3,731.0	+15.0	-305.0	-1.2	5,649.0	22.7	4,024.0	16.1	120.0	.5	1,498.0	6.1	7.0	Neg.	5,649.0	22.7
Louisiana	43,891.0	176.0	-735.0	-3.0	-13,473.0	-53.9	-8,045.0	-32.3	21,638.0	86.8	2,540.0	10.2	18,541.0	74.4	548.0	2.2	9.0	Neg.	21,638.0	86.8
Oklahoma	25,838.0	103.6	-73.0	-.3	-12,719.0	-51.0	-5,469.0	-21.9	7,577.0	30.4	5,461.0	21.9	410.0	1.6	1,687.0	6.8	19.0	.1	7,577.0	30.4
Texas	185,527.0	744.1	-1,705.0	-6.9	-43,397.0	-174.0	-26,040.0	-104.4	114,385.0	458.8	15,356.0	61.5	82,948.0	332.7	15,819.0	63.5	262.0	1.1	114,385.0	458.8
New Mexico	18,293.0	73.4	+225.0	+.9	-15,485.0	-62.1	-424.0	-1.7	2,609.0	10.5	1,786.0	7.3	111.0	.4	702.0	2.8	10.0	Neg.	2,609.0	10.5
Kansas	16,383.0	65.7	+143.0	+.6	-7,613.0	-30.6	-2,419.0	-9.7	6,494.0	26.0	4,696.0	18.7	767.0	3.1	1,018.0	4.1	13.0	.1	6,494.0	26.0
Subtotal IIb	292,077.0	1,171.4	-2,067.0	-8.4	-88,956.0	-356.6	-42,702.0	-171.2	158,352.0	635.2	33,863.0	135.7	102,897.0	412.7	21,272.0	85.5	320.0	1.3	158,352.0	635.2
Subtotal II	295,529.0	1,185.2	-1,857.0	-7.5	-62,277.0	-249.5	-45,135.0	-181.0	186,260.0	747.2	56,715.0	227.4	106,837.0	428.5	22,252.0	89.4	456.0	1.9	186,260.0	747.2
Region III:																				
Subregion IIIa:																				
Montana	1,320.0	5.2	-33.0	-.1	+244.0	+1.0	-532.0	-2.1	999.0	4.0	748.0	3.0	205.0	.8	46.0	.2	Neg.	-	999.0	4.0
Idaho	-	-	-	-	+563.0	+2.3	-	-	563.0	2.3	410.0	1.6	113.0	.5	15.0	.1	25.0	.1	563.0	2.3
Wyoming	3,895.0	15.7	+9.0	Neg.	-2,093.0	-8.4	-743.0	-3.0	1,068.0	4.3	626.0	2.5	271.0	1.1	168.0	.7	3.0	Neg.	1,068.0	4.3
Utah	942.0	3.8	+77.0	+.3	+970.0	+3.9	-1,274.0	-5.1	715.0	2.9	595.0	2.3	64.0	.3	43.0	.2	13.0	.1	715.0	2.9
Colorado	2,483.0	10.0	-28.0	-.1	+606.0	+2.4	-	-	3,061.0	12.3	2,617.0	10.5	113.0	.5	279.0	1.1	52.0	.2	3,061.0	12.3
Washington	1,336.0	5.4	-6.0	Neg.	+31.0	+.1	-	-	1,361.0	5.5	1,051.0	4.2	225.0	.9	71.0	.3	14.0	.1	1,361.0	5.5
Oregon	121.0	.5	-1.0	Neg.	+877.0	+3.5	-	-	997.0	4.0	924.0	3.8	59.0	.2	12.0	Neg.	2.0	Neg.	997.0	4.0
Subtotal IIIa	10,097.0	40.6	+18.0	+.1	+1,198.0	+4.8	-2,549.0	-10.2	8,764.0	35.3	6,971.0	27.9	1,050.0	4.3	634.0	2.6	109.0	.5	8,764.0	35.3
Subregion IIIb:																				
Arizona	-	-	-	-	+1,057.0	+4.2	-	-	1,057.0	4.2	855.0	3.4	63.0	.3	137.0	.5	2.0	Neg.	1,057.0	4.2
Nevada	-	-	-	-	+720.0	+2.9	-	-	720.0	2.9	610.0	2.5	80.0	.3	30.0	.1	Neg.	Neg.	720.0	2.9
California	18,394.0	73.8	-58.0	-.2	+1,950.0	+7.8	-6,436.0	-25.8	13,850.0	55.6	5,994.0	23.9	6,749.0	27.1	719.0	2.9	388.0	1.7	13,850.0	55.6
Subtotal IIIb	18,394.0	73.8	-58.0	-.2	+3,727.0	+14.9	-6,436.0	-25.8	15,627.0	62.7	7,459.0	29.8	6,892.0	27.7	886.0	3.5	390.0	1.7	15,627.0	62.7
Subregion IIIc:																				
Alaska	121.0	.5	-1.0	Neg.	-16.0	-.1	-	-	104.0	.4	91.0	.4	12.0	Neg.	1.0	Neg.	-	-	104.0	.4
Hawaii	242.0	1.0	-2.0	Neg.	+2.0	Neg.	-	-	242.0	1.0	133.0	.6	97.0	.4	12.0	Neg.	-	-	242.0	1.0
Subtotal IIIc	363.0	1.5	-3.0	Neg.	-14.0	-.1	-	-	346.0	1.4	224.0	1.0	109.0	.4	13.0	Neg.	-	-	346.0	1.4
Subtotal III	28,854.0	115.9	-43.0	-.1	+4,911.0	+19.6	-8,985.0	-36.0	24,737.0	99.4	14,654.0	58.7	8,051.0	32.4	1,533.0	6.1	499.0	2.2	24,737.0	99.4

Neg.--Negligible.

[1]Electricity generation, utilities sector does not apply to this commodity.

[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[3]Includes net foreign trade; 33.0 thousand barrels; 0.1 trillion Btu.

TABLE 12. - Supply and demand for jet fuel (excludes kerosine-type jet fuel) by major consumer sector, by States and Regions

1965

State and Region	Supply								Demand by major consumer sector[1]			
	Refinery output		Stock change[2]		Net shipments[3]		Total supply available for consumption		Transportation		Total domestic demand	
	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States total.	82,529.0	433.0	+1,566.0	+8.2	+30,026.0	+157.5	114,121.0	598.7	114,121.0	598.7	114,121.0	598.7
Region I:												
Subregion Ia:												
Maine	-	-	+4.0	Neg.	+3,850.0	+20.2	3,854.0	20.2	3,854.0	20.2	3,854.0	20.2
New Hampshire	-	-	+2.0	Neg.	+1,281.0	+6.7	1,283.0	6.7	1,283.0	6.7	1,283.0	6.7
Vermont	-	-	-	-	-	-	-	-	-	-	-	-
Massachusetts	-	-	+4.0	Neg.	+364.0	+1.9	368.0	1.9	368.0	1.9	368.0	1.9
Rhode Island	-	-	+1.0	Neg.	+439.0	+2.3	440.0	2.3	440.0	2.3	440.0	2.3
Connecticut	-	-	+2.0	Neg.	+2,220.0	+11.7	2,222.0	11.7	2,222.0	11.7	2,222.0	11.7
New York	612.0	3.2	-50.0	-.3	+2,925.0	+15.4	3,487.0	18.3	3,487.0	18.3	3,487.0	18.3
New Jersey	749.0	3.9	-33.0	-.2	+1,361.0	+7.2	2,077.0	10.9	2,077.0	10.9	2,077.0	10.9
Pennsylvania	1,550.0	8.1	-174.0	-.9	-390.0	-2.0	986.0	5.2	986.0	5.2	986.0	5.2
Delaware	-	-	+1.0	Neg.	+491.0	+2.6	492.0	2.6	492.0	2.6	492.0	2.6
Maryland	-	-	+3.0	Neg.	+1,277.0	+6.7	1,280.0	6.7	1,280.0	6.7	1,280.0	6.7
District of Columbia	-	-	-	-	+64.0	+.3	64.0	.3	64.0	.3	64.0	.3
Virginia	-	-	+10.0	+.1	+2,784.0	+14.6	2,794.0	14.7	2,794.0	14.7	2,794.0	14.7
West Virginia	-	-	-4.0	Neg.	+4.0	Neg.	-	-	-	-	-	-
North Carolina	-	-	+16.0	+.1	+1,367.0	+7.2	1,383.0	7.3	1,383.0	7.3	1,383.0	7.3
South Carolina	-	-	+8.0	Neg.	+891.0	+4.7	899.0	4.7	899.0	4.7	899.0	4.7
Georgia	-	-	+13.0	+.1	+2,986.0	+15.6	2,999.0	15.7	2,999.0	15.7	2,999.0	15.7
Florida	143.0	.8	+9.0	Neg.	+9,422.0	+49.4	9,574.0	50.2	9,574.0	50.2	9,574.0	50.2
Kentucky	1,206.0	6.3	-37.0	-.2	+318.0	+1.7	1,487.0	7.8	1,487.0	7.8	1,487.0	7.8
Tennessee	1,405.0	7.4	+21.0	+.1	-959.0	-5.0	467.0	2.5	467.0	2.5	467.0	2.5
Alabama	583.0	3.0	+6.0	Neg.	+162.0	+.9	751.0	3.9	751.0	3.9	751.0	3.9
Mississippi	403.0	2.1	-1.0	Neg.	+193.0	+1.0	595.0	3.1	595.0	3.1	595.0	3.1
Ohio	2,540.0	13.3	+131.0	+.7	-55.0	-.3	2,616.0	13.7	2,616.0	13.7	2,616.0	13.7
Subtotal Ia	9,191.0	48.1	-68.0	-.5	+30,995.0	+162.8	40,118.0	210.4	40,118.0	210.4	40,118.0	210.4
Region Ib:												
Indiana	2,815.0	14.8	+220.0	+1.2	+931.0	+4.8	3,966.0	20.8	3,966.0	20.8	3,966.0	20.8
Illinois	597.0	3.1	+16.0	+.1	-204.0	-1.1	409.0	2.1	409.0	2.1	409.0	2.1
Michigan	283.0	1.5	+41.0	+.2	+2,648.0	+13.9	2,972.0	15.6	2,972.0	15.6	2,972.0	15.6
Wisconsin	-	-	+6.0	Neg.	+541.0	+2.9	547.0	2.9	547.0	2.9	547.0	2.9
Subtotal Ib	3,695.0	19.4	+283.0	+1.5	+3,916.0	+20.5	7,894.0	41.4	7,894.0	41.4	7,894.0	41.4
Subtotal I	12,886.0	67.5	+215.0	+1.0	+34,911.0	+183.3	48,012.0	251.8	48,012.0	251.8	48,012.0	251.8
Region II:												
Subregion IIa:												
Minnesota	1,622.0	8.5	-63.0	-.3	-1,039.0	-5.5	520.0	2.7	520.0	2.7	520.0	2.7
Iowa	-	-	-16.0	-.1	+1,009.0	+5.3	993.0	5.2	993.0	5.2	993.0	5.2
Missouri	1,208.0	6.3	-21.0	-.1	-784.0	-4.1	403.0	2.1	403.0	2.1	403.0	2.1
North Dakota	484.0	2.5	+58.0	+.3	+1,639.0	+8.6	2,181.0	11.4	2,181.0	11.4	2,181.0	11.4
South Dakota	-	-	+2.0	Neg.	+1,614.0	+8.5	1,616.0	8.5	1,616.0	8.5	1,616.0	8.5
Nebraska	-	-	-6.0	Neg.	+1,200.0	+6.3	1,194.0	6.3	1,194.0	6.3	1,194.0	6.3
Subtotal IIa	3,314.0	17.3	-46.0	-.2	+3,639.0	+19.1	6,907.0	36.2	6,907.0	36.2	6,907.0	36.2
Subregion IIb:												
Arkansas	30.0	.2	+4.0	Neg.	+61.0	+.3	95.0	.5	95.0	.5	95.0	.5
Louisiana	10,270.0	53.9	+289.0	+1.5	-7,863.0	-41.3	2,696.0	14.1	2,696.0	14.1	2,696.0	14.1
Oklahoma	4,896.0	25.7	-74.0	-.4	-2,595.0	-13.6	2,227.0	11.7	2,227.0	11.7	2,227.0	11.7
Texas	25,998.0	136.4	+810.0	+4.4	-13,733.0	-72.2	13,075.0	68.6	13,075.0	68.6	13,075.0	68.6
New Mexico	1,393.0	7.4	-17.0	-.1	-486.0	-2.6	890.0	4.7	890.0	4.7	890.0	4.7
Kansas	857.0	4.5	-53.0	-.3	+1,106.0	+5.8	1,910.0	10.0	1,910.0	10.0	1,910.0	10.0
Subtotal IIb	43,444.0	228.1	+959.0	+5.1	-23,510.0	-123.6	20,893.0	109.6	20,893.0	109.6	20,893.0	109.6
Subtotal II	46,758.0	245.4	+913.0	+4.9	-19,871.0	-104.5	27,800.0	145.8	27,800.0	145.8	27,800.0	145.8
Region III:												
Subregion IIIa:												
Montana	2,818.0	14.8	+139.0	+.7	-1,686.0	-8.8	1,271.0	6.7	1,271.0	6.7	1,271.0	6.7
Idaho	-	-	+4.0	Neg.	+332.0	+1.8	336.0	1.8	336.0	1.8	336.0	1.8
Wyoming	1,485.0	7.8	+25.0	+.1	-1,502.0	-7.9	8.0	Neg.	8.0	Neg.	8.0	Neg.
Utah	1,145.0	6.1	-53.0	-.3	-244.0	-1.3	848.0	4.5	848.0	4.5	848.0	4.5
Colorado	131.0	.7	+15.0	+.1	+235.0	+1.2	381.0	2.0	381.0	2.0	381.0	2.0
Washington	1,904.0	10.0	+21.0	+.1	-474.0	-2.5	1,451.0	7.6	1,451.0	7.6	1,451.0	7.6
Oregon	173.0	.9	-17.0	-.1	-156.0	-.8	-	-	-	-	-	-
Subtotal IIIa	7,656.0	40.3	+134.0	+.6	-3,495.0	-18.3	4,295.0	22.6	4,295.0	22.6	4,295.0	22.6
Subregion IIIb:												
Arizona	-	-	-8.0	Neg.	+2,250.0	+11.8	2,242.0	11.8	2,242.0	11.8	2,242.0	11.8
Nevada	-	-	-4.0	Neg.	+456.0	+2.4	452.0	2.4	452.0	2.4	452.0	2.4
California	14,710.0	77.1	+307.0	+1.7	+14,718.0	+77.2	29,735.0	156.0	29,735.0	156.0	29,735.0	156.0
Subtotal IIIb	14,710.0	77.1	+295.0	+1.7	+17,424.0	+91.4	32,429.0	170.2	32,429.0	170.2	32,429.0	170.2
Subregion IIIc:												
Alaska	173.0	.9	+2.0	Neg.	+717.0	+3.8	892.0	4.7	892.0	4.7	892.0	4.7
Hawaii	346.0	1.8	+7.0	Neg.	+340.0	+1.8	693.0	3.6	693.0	3.6	693.0	3.6
Subtotal IIIc	519.0	2.7	+9.0	Neg.	+1,057.0	+5.6	1,585.0	8.3	1,585.0	8.3	1,585.0	8.3
Subtotal III	22,885.0	120.1	+438.0	+2.3	+14,986.0	+78.7	38,309.0	201.1	38,309.0	201.1	38,309.0	201.1

Neg.--Negligible.

[1]Household and commercial; industrial; electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.

[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[3]Includes net foreign trade: 16,493.0 thousand barrels; 86.6 trillion Btu.

TABLE 13. - Supply and demand for gasoline by major consumer sector, by States and Regions

1965

State and Region	Supply: Refinery output, Thousand barrels	Refinery output, Trillion Btu	Stock change[2], Thousand barrels	Stock change[2], Trillion Btu	Net shipments[3], Thousand barrels	Net shipments[3], Trillion Btu	Total supply available for consumption, Thousand barrels	Total supply available for consumption, Trillion Btu	Demand by major consumer sector: Transportation, Thousand barrels	Transportation, Trillion Btu	Total demand, Thousand barrels
United States total.	1,693,741.0	8,888.8	+11,633.0	+61.0	+14,826.0	+77.8	1,720,200.0	9,027.6	1,720,200.0	9,027.6	1,720,200.0
Region I:											
Subregion Ia:											
Maine	-	-	+96.0	+.5	+8,943.0	+46.9	9,039.0	47.4	9,039.0	47.4	9,039.0
New Hampshire	-	-	+44.0	+.2	+5,706.0	+30.0	5,750.0	30.2	5,750.0	30.2	5,750.0
Vermont	-	-	+38.0	+.2	+3,686.0	+19.3	3,724.0	19.5	3,724.0	19.5	3,724.0
Massachusetts	-	-	+372.0	+2.0	+39,141.0	+205.4	39,513.0	207.4	39,513.0	207.4	39,513.0
Rhode Island	-	-	+67.0	+.4	+6,471.0	+33.9	6,538.0	34.3	6,538.0	34.3	6,538.0
Connecticut	-	-	+67.0	+.4	+22,519.0	+118.1	22,586.0	118.5	22,586.0	118.5	22,586.0
New York	12,849.0	67.4	+733.0	+3.8	+106,682.0	+559.9	120,264.0	631.1	120,264.0	631.1	120,264.0
New Jersey	74,003.0	388.4	+375.0	+2.0	-19,105.0	-100.3	55,273.0	290.1	55,273.0	290.1	55,273.0
Pennsylvania	101,585.0	533.1	+241.0	+1.3	-16,479.0	-86.5	85,347.0	447.9	85,347.0	447.9	85,347.0
Delaware	22,174.0	116.4	-195.0	-1.0	-16,591.0	-87.1	5,388.0	28.3	5,388.0	28.3	5,388.0
Maryland	-	-	+307.0	+1.6	+26,655.0	+139.9	26,962.0	141.5	26,962.0	141.5	26,962.0
District of Columbia	-	-	+5.0	Neg.	+5,315.0	+27.9	5,320.0	27.9	5,320.0	27.9	5,320.0
Virginia	6,887.0	36.1	+207.0	+1.1	+30,215.0	+158.6	37,309.0	195.8	37,309.0	195.8	37,309.0
West Virginia	642.0	3.4	+118.0	+.6	+11,937.0	+62.6	12,697.0	66.6	12,697.0	66.6	12,697.0
North Carolina	-	-	+451.0	+2.4	+42,747.0	+224.3	43,198.0	226.7	43,198.0	226.7	43,198.0
South Carolina	-	-	+229.0	+1.2	+20,804.0	+109.2	21,033.0	110.4	21,033.0	110.4	21,033.0
Georgia	-	-	+376.0	+2.0	+38,891.0	+204.1	39,267.0	206.1	39,267.0	206.1	39,267.0
Florida	-	-	+327.0	+1.7	+53,860.0	+282.7	54,187.0	284.4	54,187.0	284.4	54,187.0
Kentucky	15,901.0	83.4	+430.0	+2.3	+9,715.0	+51.0	26,046.0	136.7	26,046.0	136.7	26,046.0
Tennessee	2,500.0	13.1	+235.0	+1.2	+30,302.0	+159.1	33,037.0	173.4	33,037.0	173.4	33,037.0
Alabama	100.0	.5	+86.0	+.5	+28,809.0	+151.2	28,995.0	152.2	28,995.0	152.2	28,995.0
Mississippi	5,100.0	26.8	-43.0	-.2	+13,523.0	+70.9	18,580.0	97.5	18,580.0	97.5	18,580.0
Ohio	92,765.0	486.8	+2.0	Neg.	-6,161.0	-32.3	86,606.0	454.5	86,606.0	454.5	86,606.0
Subtotal Ia	334,506.0	1,755.4	+4,568.0	+24.2	+447,585.0	+2,348.8	786,659.0	4,128.4	786,659.0	4,128.4	786,659.0
Subregion Ib:											
Indiana	81,841.0	429.5	+1,391.0	+7.2	-34,887.0	-183.0	48,345.0	253.7	48,345.0	253.7	48,345.0
Illinois	118,032.0	619.4	+928.0	+4.9	-32,997.0	-173.2	85,963.0	451.1	85,963.0	451.1	85,963.0
Michigan	25,486.0	133.8	+889.0	+4.6	+51,459.0	+270.1	77,834.0	408.5	77,834.0	408.5	77,834.0
Wisconsin	3,000.0	15.7	-142.0	-.7	+33,371.0	+175.1	36,229.0	190.1	36,229.0	190.1	36,229.0
Subtotal Ib	228,359.0	1,198.4	+3,066.0	+16.0	+16,946.0	+89.0	248,371.0	1,303.4	248,371.0	1,303.4	248,371.0
Subtotal I	562,865.0	2,953.8	+7,634.0	+40.2	+464,531.0	+2,437.8	1,035,030.0	5,431.8	1,035,030.0	5,431.8	1,035,030.0
Region II:											
Subregion IIa:											
Minnesota	15,362.0	80.6	+221.0	+1.2	+19,888.0	+104.4	35,471.0	186.2	35,471.0	186.2	35,471.0
Iowa	-	-	+25.0	+.1	+31,145.0	+163.5	31,170.0	163.6	31,170.0	163.6	31,170.0
Missouri	12,531.0	65.8	+180.0	+.9	+33,199.0	+174.2	45,910.0	240.9	45,910.0	240.9	45,910.0
North Dakota	9,982.0	52.5	-70.0	-.4	-1,631.0	-8.6	8,281.0	43.5	8,281.0	43.5	8,281.0
South Dakota	-	-	-32.0	-.2	+9,272.0	+48.7	9,240.0	48.5	9,240.0	48.5	9,240.0
Nebraska	600.0	3.1	-3.0	Neg.	+15,924.0	+83.6	16,521.0	86.7	16,521.0	86.7	16,521.0
Subtotal IIa	38,475.0	202.0	+321.0	+1.6	+107,797.0	+565.8	146,593.0	769.4	146,593.0	769.4	146,593.0
Subregion IIb:											
Arkansas	13,572.0	71.2	+76.0	+.4	+4,390.0	+23.1	18,038.0	94.7	18,038.0	94.7	18,038.0
Louisiana	167,649.0	879.8	-326.0	-1.7	-139,305.0	-731.1	28,018.0	147.0	28,018.0	147.0	28,018.0
Oklahoma	78,712.0	413.1	+815.0	+4.3	-49,541.0	-260.0	29,986.0	157.4	29,986.0	157.4	29,986.0
Texas	465,567.0	2,443.3	+1,612.0	+8.4	-341,945.0	-1,794.6	125,234.0	657.1	125,234.0	657.1	125,234.0
New Mexico	7,069.0	37.1	-90.0	-.5	+4,001.0	+21.0	10,980.0	57.6	10,980.0	57.6	10,980.0
Kansas	68,158.0	357.8	+522.0	+2.7	-42,485.0	-223.0	26,195.0	137.5	26,195.0	137.5	26,195.0
Subtotal IIb	800,727.0	4,202.3	+2,609.0	+13.6	-564,885.0	-2,964.6	238,451.0	1,251.3	238,451.0	1,251.3	238,451.0
Subtotal II	839,202.0	4,404.3	+2,930.0	+15.2	-457,088.0	-2,398.8	385,044.0	2,020.7	385,044.0	2,020.7	385,044.0
Region III:											
Subregion IIIa:											
Montana	15,603.0	81.8	+70.0	+.4	-6,519.0	-34.2	9,154.0	48.0	9,154.0	48.0	9,154.0
Idaho	-	-	+22.0	+.1	+7,563.0	+39.7	7,585.0	39.8	7,585.0	39.8	7,585.0
Wyoming	18,523.0	97.2	-1.0	Neg.	-13,773.0	-72.3	4,749.0	24.9	4,749.0	24.9	4,749.0
Utah	19,174.0	100.6	+11.0	+.1	-8,665.0	-45.5	10,520.0	55.2	10,520.0	55.2	10,520.0
Colorado	6,302.0	33.1	+97.0	+.5	+12,762.0	+67.0	19,161.0	100.6	19,161.0	100.6	19,161.0
Washington	23,207.0	121.8	+160.0	+.8	+5,371.0	+28.2	28,738.0	150.8	28,738.0	150.8	28,738.0
Oregon	-	-	+102.0	+.5	+19,524.0	+102.5	19,626.0	103.0	19,626.0	103.0	19,626.0
Subtotal IIIa	82,809.0	434.5	+461.0	+2.4	+16,263.0	+85.4	99,533.0	522.3	99,533.0	522.3	99,533.0
Subregion IIIb:											
Arizona	-	-	+42.0	+.2	+14,993.0	+78.7	15,035.0	78.9	15,035.0	78.9	15,035.0
Nevada	-	-	+19.0	+.1	+5,673.0	+29.8	5,692.0	29.9	5,692.0	29.9	5,692.0
California	206,544.0	1,084.0	+521.0	+2.7	-33,672.0	-176.7	173,393.0	910.0	173,393.0	910.0	173,393.0
Subtotal IIIb	206,544.0	1,084.0	+582.0	+3.0	-13,006.0	-68.2	194,120.0	1,018.8	194,120.0	1,018.8	194,120.0
Subregion IIIc:											
Alaska	-	-	+14.0	+.1	+1,844.0	+9.7	1,858.0	9.8	1,858.0	9.8	1,858.0
Hawaii	2,321.0	12.2	+12.0	+.1	+2,282.0	+11.9	4,615.0	24.2	4,615.0	24.2	4,615.0
Subtotal IIIc	2,321.0	12.2	+26.0	+.2	+4,126.0	+21.6	6,473.0	34.0	6,473.0	34.0	6,473.0
Subtotal III	291,674.0	1,530.7	+1,069.0	+5.6	+7,383.0	+38.8	300,126.0	1,575.1	300,126.0	1,575.1	300,126.0

Neg.--Negligible.

[1]Household and commercial; industrial; electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.

[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[3]Includes net foreign trade: 5,180.0 thousand barrels; 27.7 trillion Btu.

TABLE 14. - Supply and demand for kerosine and kerosine-type jet fuel by major consumer sector, by States and Regions

1965

State and Region	Supply: Refinery output, Thousand barrels	Supply: Refinery output, Trillion Btu	Supply: Stock change[2], Thousand barrels	Supply: Stock change[2], Trillion Btu	Supply: Net shipments[3], Thousand barrels	Supply: Net shipments[3], Trillion Btu	Supply: Total supply available for consumption, Thousand barrels	Supply: Total supply available for consumption, Trillion Btu	Demand by major consumer sector[1]: Household and commercial, Thousand barrels	Household and commercial, Trillion Btu	Industrial, Thousand barrels	Industrial, Trillion Btu	Transportation, Thousand barrels	Transportation, Trillion Btu	Total domestic demand, Thousand barrels	Total domestic demand, Trillion Btu
United States total.	201,788.0	1,150.5	+1,724.0	+9.8	+2,452.0	+13.9	205,964.0	1,174.2	79,188.0	449.0	18,461.0	104.3	108,315.0	620.9	205,964.0	1,174.2
Region I:																
Subregion Ia:																
Maine	-	-	+72.0	+.4	+1,981.0	+11.3	2,053.0	11.7	1,798.0	10.2	255.0	1.5	-	-	2,053.0	11.7
New Hampshire	-	-	+33.0	+.2	+726.0	+4.1	759.0	4.3	737.0	4.2	22.0	.1	-	-	759.0	4.3
Vermont	-	-	+28.0	+.2	+735.0	+4.1	763.0	4.3	746.0	4.2	15.0	.1	2.0	Neg.	763.0	4.3
Massachusetts	-	-	+134.0	+.8	+5,962.0	+34.0	6,096.0	34.8	2,994.0	17.0	504.0	2.9	2,598.0	14.9	6,096.0	34.8
Rhode Island	-	-	+21.0	+.1	+645.0	+3.7	666.0	3.8	604.0	3.4	62.0	.4	-	-	666.0	3.8
Connecticut	-	-	+50.0	+.3	+2,385.0	+13.6	2,435.0	13.9	1,189.0	6.7	120.0	.7	1,126.0	6.5	2,435.0	13.9
New York	932.0	5.3	+336.0	+1.9	+24,994.0	+143.0	26,262.0	150.2	4,830.0	27.4	797.0	4.5	20,635.0	118.3	26,262.0	150.2
New Jersey	7,474.0	42.6	+42.0	+.2	-2,809.0	-15.9	4,707.0	26.9	1,708.0	9.7	389.0	2.2	2,610.0	15.0	4,707.0	26.9
Pennsylvania	6,452.0	36.6	+14.0	+.1	-41.0	-.2	6,425.0	36.5	3,130.0	17.7	724.0	4.1	2,571.0	14.7	6,425.0	36.5
Delaware	1,326.0	7.6	+90.0	+.5	-526.0	-3.0	890.0	5.1	692.0	3.9	134.0	.8	64.0	.4	890.0	5.1
Maryland	-	-	+142.0	+.8	+3,627.0	+20.7	3,769.0	21.5	2,273.0	12.9	100.0	.6	1,396.0	8.0	3,769.0	21.5
District of Columbia	-	-	+3.0	Neg.	+101.0	+.6	104.0	.6	87.0	.5	17.0	.1	-	-	104.0	.6
Virginia	-	-	+211.0	+1.2	+8,076.0	+46.0	8,287.0	47.2	5,057.0	28.7	491.0	2.8	2,739.0	15.7	8,287.0	47.2
West Virginia	38.0	.2	+14.0	+.1	+230.0	+1.4	282.0	1.7	203.0	1.2	50.0	.3	29.0	.2	282.0	1.7
North Carolina	-	-	+344.0	+2.0	+12,842.0	+72.7	13,186.0	74.7	10,976.0	62.3	1,750.0	9.8	460.0	2.6	13,186.0	74.7
South Carolina	-	-	+162.0	+.9	+3,161.0	+17.9	3,323.0	18.8	2,795.0	15.8	504.0	2.9	24.0	.1	3,323.0	18.8
Georgia	-	-	+268.0	+1.5	+1,082.0	+6.1	1,350.0	7.6	730.0	4.1	568.0	3.2	52.0	.3	1,350.0	7.6
Florida	-	-	+248.0	+1.4	+13,811.0	+78.9	14,059.0	80.3	3,210.0	18.2	1,242.0	7.0	9,607.0	55.1	14,059.0	80.3
Kentucky	2,403.0	13.6	-31.0	-.2	+591.0	+3.4	2,963.0	16.8	2,231.0	12.6	146.0	.8	586.0	3.4	2,963.0	16.8
Tennessee	38.0	.2	+20.0	+.1	+2,770.0	+15.7	2,828.0	16.0	1,426.0	8.1	1,116.0	6.3	286.0	1.6	2,828.0	16.0
Alabama	37.0	.2	-6.0	Neg.	+973.0	+5.4	1,004.0	5.6	619.0	3.5	290.0	1.6	95.0	.5	1,004.0	5.6
Mississippi	16.0	.1	+13.0	+.1	+372.0	+2.1	401.0	2.3	141.0	.8	205.0	1.2	55.0	.3	401.0	2.3
Ohio	5,201.0	29.6	-112.0	-.6	+2,654.0	+15.0	7,743.0	44.0	5,479.0	31.1	853.0	4.8	1,411.0	8.1	7,743.0	44.0
Subtotal Ia	23,917.0	136.0	+2,096.0	+12.0	+84,342.0	+480.6	110,355.0	628.6	53,655.0	304.2	10,354.0	58.7	46,346.0	265.7	110,355.0	628.6
Subregion Ib:																
Indiana	8,295.0	47.4	+135.0	+.8	+1,472.0	+8.3	9,902.0	56.5	2,813.0	15.9	633.0	3.6	6,456.0	37.0	9,902.0	56.5
Illinois	17,092.0	97.2	-124.0	-.7	-7,137.0	-40.5	9,831.0	56.0	4,384.0	24.9	957.0	5.4	4,490.0	25.7	9,831.0	56.0
Michigan	2,827.0	16.0	+36.0	+.2	+3,876.0	+22.0	6,739.0	38.2	4,679.0	26.5	1,205.0	6.8	855.0	4.9	6,739.0	38.2
Wisconsin	-	-	-2.0	Neg.	+1,335.0	+7.6	1,333.0	7.6	1,169.0	6.6	81.0	.5	83.0	.5	1,333.0	7.6
Subtotal Ib	28,214.0	160.6	+45.0	+.3	-454.0	-2.6	27,805.0	158.3	13,045.0	73.9	2,876.0	16.3	11,884.0	68.1	27,805.0	158.3
Subtotal I	52,131.0	296.6	+2,141.0	+12.3	+83,888.0	+478.0	138,160.0	786.9	66,700.0	378.1	13,230.0	75.0	58,230.0	333.8	138,160.0	786.9
Region II:																
Subregion IIa:																
Minnesota	584.0	3.3	-27.0	-.2	+3,542.0	+20.2	4,099.0	23.3	2,071.0	11.7	244.0	1.4	1,784.0	10.2	4,099.0	23.3
Iowa	1,363.0	7.7	-10.0	-.1	+213.0	+1.2	1,566.0	8.8	1,382.0	7.8	142.0	.8	42.0	.2	1,566.0	8.8
Missouri	-	-	-170.0	-1.0	+3,935.0	+22.5	3,765.0	21.5	1,037.0	5.9	126.0	.7	2,602.0	14.9	3,765.0	21.5
North Dakota	1,463.0	8.3	+7.0	Neg.	-1,358.0	-7.7	112.0	.6	40.0	.2	12.0	.1	60.0	.3	112.0	.6
South Dakota	-	-	-1.0	Neg.	+578.0	+3.3	577.0	3.3	524.0	3.0	39.0	.2	14.0	.1	577.0	3.3
Nebraska	5.0	Neg.	-3.0	Neg.	+977.0	+5.6	979.0	5.6	645.0	3.7	146.0	.8	188.0	1.1	979.0	5.6
Subtotal IIa	3,415.0	19.3	-204.0	-1.3	+7,887.0	+45.1	11,098.0	63.1	5,699.0	32.3	709.0	4.0	4,690.0	26.8	11,098.0	63.1
Subregion IIb:																
Arkansas	1,825.0	10.4	+4.0	Neg.	-1,439.0	-8.2	390.0	2.2	214.0	1.2	172.0	1.0	4.0	Neg.	390.0	2.2
Louisiana	33,370.0	190.5	+279.0	+1.6	-29,214.0	-166.8	4,435.0	25.3	461.0	2.6	343.0	1.9	3,631.0	20.8	4,435.0	25.3
Oklahoma	7,225.0	40.9	-339.0	-1.9	-5,486.0	-31.1	1,400.0	7.9	850.0	4.8	96.0	.5	454.0	2.6	1,400.0	7.9
Texas	66,924.0	382.0	+752.0	+4.3	-58,248.0	-332.6	9,428.0	53.7	895.0	5.1	2,566.0	14.4	5,967.0	34.2	9,428.0	53.7
New Mexico	189.0	1.1	-13.0	-.1	+606.0	+3.4	782.0	4.4	195.0	1.1	181.0	1.0	406.0	2.3	782.0	4.4
Kansas	2,721.0	15.5	+76.0	+.4	-886.0	-5.0	1,911.0	10.9	1,677.0	9.5	137.0	.8	97.0	.6	1,911.0	10.9
Subtotal IIb	112,254.0	640.4	+759.0	+4.3	-94,667.0	-540.3	18,346.0	104.4	4,292.0	24.3	3,495.0	19.6	10,559.0	60.5	18,346.0	104.4
Subtotal II	115,669.0	659.7	+555.0	+3.0	-86,780.0	-495.2	29,444.0	167.5	9,991.0	56.6	4,204.0	23.6	15,249.0	87.3	29,444.0	167.5
Region III:																
Subregion IIIa:																
Montana	709.0	4.0	+50.0	+.3	-390.0	-2.2	369.0	2.1	227.0	1.3	21.0	.1	121.0	.7	369.0	2.1
Idaho	-	-	+5.0	Neg.	+569.0	+3.3	574.0	3.3	500.0	2.9	21.0	.1	53.0	.3	574.0	3.3
Wyoming	1,342.0	7.6	+4.0	Neg.	-1,119.0	-6.3	227.0	1.3	179.0	1.0	27.0	.2	21.0	.1	227.0	1.3
Utah	837.0	4.7	+9.0	+.1	+103.0	+.6	949.0	5.4	403.0	2.3	71.0	.4	475.0	2.7	949.0	5.4
Colorado	609.0	3.5	+6.0	Neg.	+3,183.0	+18.1	3,798.0	21.6	947.0	5.3	162.0	.9	2,689.0	15.4	3,798.0	21.6
Washington	3,354.0	19.2	-163.0	-.9	-60.0	-.3	3,131.0	18.0	11.0	.1	23.0	.1	3,097.0	17.8	3,131.0	18.0
Oregon	305.0	1.7	-76.0	-.4	+552.0	+3.2	779.0	4.5	10.0	.1	9.0	Neg.	760.0	4.4	779.0	4.5
Subtotal IIIa	7,156.0	40.7	-167.0	-.9	+2,838.0	+16.4	9,827.0	56.2	2,277.0	13.0	334.0	1.8	7,216.0	41.4	9,827.0	56.2
Subregion IIIb:																
Arizona	-	-	-30.0	-.2	+1,204.0	+7.0	1,174.0	6.8	12.0	.1	19.0	.1	1,143.0	6.6	1,174.0	6.8
Nevada	-	-	-14.0	-.1	+664.0	+3.8	650.0	3.7	1.0	Neg.	4.0	Neg.	645.0	3.7	650.0	3.7
California	25,917.0	148.3	-726.0	-4.1	-4,007.0	-22.9	21,184.0	121.3	158.0	.9	660.0	3.7	20,366.0	116.7	21,184.0	121.3
Subtotal IIIb	25,917.0	148.3	-770.0	-4.4	-2,139.0	-12.1	23,008.0	131.8	171.0	1.0	683.0	3.8	22,154.0	127.0	23,008.0	131.8
Subregion IIIc:																
Alaska	305.0	1.7	-16.0	-.1	+991.0	+5.8	1,280.0	7.4	10.0	.1	-	-	1,270.0	7.3	1,280.0	7.4
Hawaii	610.0	3.5	-19.0	-.1	+3,654.0	+21.0	4,245.0	24.4	39.0	.2	10.0	.1	4,196.0	24.1	4,245.0	24.4
Subtotal IIIc	915.0	5.2	-35.0	-.2	+4,645.0	+26.8	5,525.0	31.8	49.0	.3	10.0	.1	5,466.0	31.4	5,525.0	31.8
Subtotal III	33,988.0	194.2	-972.0	-5.5	+5,344.0	+31.1	38,360.0	219.8	2,497.0	14.3	1,027.0	5.7	34,836.0	199.8	38,360.0	219.8

Neg.--Negligible.
[1]Electricity generation, utilities; and miscellaneous and unaccounted for sectors do not apply to this commodity.
[2]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.
[3]Includes net foreign trade: 12,763.0 thousand barrels; 72.4 trillion Btu.

TABLE 15. - Supply and demand for distillate fuel oil by major consumer sector, by States and Regions

1965

State and Region	Supply: Refinery output, Thousand barrels	Supply: Refinery output, Trillion Btu	Supply: Stock change[1], Thousand barrels	Supply: Stock change[1], Trillion Btu	Supply: Net shipments[2], Thousand barrels	Supply: Net shipments[2], Trillion Btu	Supply: Total supply available for consumption, Thousand barrels	Supply: Total supply available for consumption, Trillion Btu	Demand: Household and commercial, Thousand barrels	Demand: Household and commercial, Trillion Btu	Demand: Industrial, Thousand barrels	Demand: Industrial, Trillion Btu	Demand: Transportation, Thousand barrels	Demand: Transportation, Trillion Btu	Demand: Electricity generation, utilities, Thousand barrels	Demand: Electricity generation, utilities, Trillion Btu	Demand: Miscellaneous and unaccounted for, Thousand barrels	Demand: Miscellaneous and unaccounted for, Trillion Btu	Demand: Total domestic demand, Thousand barrels	Demand: Total domestic demand, Trillion Btu
United States total.	765,071.0	4,456.2	+439.0	+2.6	+10,551.0	+61.4	776,061.0	4,520.2	481,000.0	2,801.8	52,800.0	307.6	185,600.0	1,081.1	3,661.0	21.0	53,000.0	308.7	776,061.0	4,520.2
Region I:																				
Subregion Ia:																				
Maine	-	-	+32.0	+.2	+9,419.0	+54.9	9,451.0	55.1	7,734.0	45.1	290.0	1.7	1,185.0	6.9	147.0	.8	95.0	.6	9,451.0	55.1
New Hampshire	-	-	+14.0	+.1	+5,929.0	+34.5	5,943.0	34.6	5,547.0	32.3	134.0	.8	176.0	1.0	-	-	86.0	.5	5,943.0	34.6
Vermont	-	-	+13.0	+.1	+4,331.0	+25.2	4,344.0	25.3	3,982.0	23.2	123.0	.7	183.0	1.1	3.0	Neg.	53.0	.3	4,344.0	25.3
Massachusetts	12.0	.1	+361.0	+2.1	+56,702.0	+330.2	57,075.0	332.4	52,639.0	306.5	1,054.0	6.1	2,603.0	15.2	318.0	1.9	461.0	2.7	57,075.0	332.4
Rhode Island	662.0	3.9	+779.0	+4.5	+5,613.0	+32.8	7,054.0	41.2	6,365.0	37.1	160.0	.9	388.0	2.3	44.0	.3	97.0	.6	7,054.0	41.2
Connecticut	-	-	+22.0	+.1	+21,516.0	+125.4	21,538.0	125.5	19,034.0	110.9	914.0	5.3	1,400.0	8.2	18.0	.1	172.0	1.0	21,538.0	125.5
New York	6,409.0	37.3	+552.0	+3.2	+98,042.0	+571.0	105,003.0	611.5	88,792.0	517.1	5,522.0	32.2	8,702.0	50.6	184.0	1.1	1,803.0	10.5	105,003.0	611.5
New Jersey	53,396.0	311.0	+1,068.0	+6.2	-275.0	-1.6	54,189.0	315.6	44,871.0	261.3	2,211.0	12.9	5,897.0	34.4	42.0	.2	1,168.0	6.8	54,189.0	315.6
Pennsylvania	48,134.0	280.2	+311.0	+1.8	+6,022.0	+35.1	54,467.0	317.1	38,558.0	224.6	4,521.0	26.3	8,801.0	51.2	88.0	.5	2,499.0	14.5	54,467.0	317.1
Delaware	10,989.0	64.0	+54.0	+.3	-7,695.0	-44.8	3,348.0	19.5	2,714.0	15.8	157.0	.9	253.0	1.5	51.0	.3	173.0	1.0	3,348.0	19.5
Maryland	312.0	1.8	+848.0	+4.9	+16,028.0	+93.5	17,188.0	100.2	11,581.0	67.5	786.0	4.6	3,731.0	21.7	148.0	.9	942.0	5.5	17,188.0	100.2
District of Columbia	-	-	+2.0	Neg.	+3,530.0	+20.6	3,532.0	20.6	2,393.0	13.9	13.0	.1	865.0	5.0	80.0	.5	181.0	1.1	3,532.0	20.6
Virginia	4,482.0	26.1	+128.0	+.7	+14,044.0	+81.8	18,654.0	108.6	10,131.0	59.0	950.0	5.5	6,490.0	37.8	41.0	.2	1,042.0	6.1	18,654.0	108.6
West Virginia	687.0	4.0	-19.0	-.1	+2,129.0	+12.4	2,797.0	16.3	629.0	3.7	398.0	2.3	1,514.0	8.8	-	-	256.0	1.5	2,797.0	16.3
North Carolina	-	-	+154.0	+.9	+16,937.0	+98.6	17,091.0	99.5	10,063.0	58.6	1,013.0	5.9	4,408.0	25.7	25.0	.1	1,582.0	9.2	17,091.0	99.5
South Carolina	-	-	+86.0	+.5	+4,672.0	+27.3	4,758.0	27.8	2,282.0	13.3	268.0	1.6	1,539.0	9.0	-	-	669.0	3.9	4,758.0	27.8
Georgia	95.0	.6	+132.0	+.8	+8,052.0	+46.9	8,279.0	48.3	1,563.0	9.1	1,159.0	6.8	4,130.0	24.1	-	-	1,427.0	8.3	8,279.0	48.3
Florida	357.0	2.1	+120.0	+.7	+11,537.0	+67.2	12,014.0	70.0	3,757.0	21.9	1,676.0	9.8	4,432.0	25.8	375.0	2.2	1,774.0	10.3	12,014.0	70.0
Kentucky	8,785.0	51.2	+65.0	+.4	-3,398.0	-19.9	5,452.0	31.7	1,553.0	9.0	457.0	2.7	2,695.0	15.7	3.0	Neg.	744.0	4.3	5,452.0	31.7
Tennessee	2,178.0	12.7	+80.0	+.5	+4,805.0	+27.9	7,063.0	41.1	1,018.0	5.9	534.0	3.1	4,298.0	25.0	2.0	Neg.	1,211.0	7.1	7,063.0	41.1
Alabama	653.0	3.8	+26.0	+.2	+4,400.0	+25.6	5,079.0	29.6	464.0	2.7	684.0	4.0	3,056.0	17.8	-	-	875.0	5.1	5,079.0	29.6
Mississippi	1,938.0	11.3	+37.0	+.2	+641.0	+3.7	2,616.0	15.2	209.0	1.2	302.0	1.8	1,123.0	6.5	-	-	982.0	5.7	2,616.0	15.2
Ohio	29,038.0	169.1	+98.0	+.6	-1,511.0	-8.8	27,625.0	160.9	13,685.0	79.7	2,278.0	13.3	9,614.0	56.0	147.0	.8	1,901.0	11.1	27,625.0	160.9
Subtotal Ia	168,127.0	979.2	+4,963.0	+28.9	+281,470.0	+1,639.5	454,560.0	2,647.6	329,564.0	1,919.4	25,604.0	149.3	77,483.0	451.3	1,716.0	9.9	20,193.0	117.7	454,560.0	2,647.6
Subregion Ib:																				
Indiana	34,283.0	199.7	-491.0	-2.9	-7,619.0	-44.4	26,173.0	152.4	17,077.0	99.5	2,975.0	17.3	5,066.0	29.5	57.0	.3	998.0	5.8	26,173.0	152.4
Illinois	47,544.0	276.9	-393.0	-2.3	-5,843.0	-34.2	41,308.0	240.4	24,951.0	145.3	3,146.0	18.3	11,381.0	66.2	162.0	.9	1,668.0	9.7	41,308.0	240.4
Michigan	12,075.0	70.3	+350.0	+2.0	+18,490.0	+107.8	30,915.0	180.1	24,109.0	140.4	1,522.0	8.9	3,311.0	19.3	376.0	2.2	1,597.0	9.3	30,915.0	180.1
Wisconsin	1,644.0	9.6	-76.0	-.4	+22,309.0	+129.8	23,877.0	139.0	20,274.0	118.1	572.0	3.3	2,124.0	12.4	23.0	.1	884.0	5.1	23,877.0	139.0
Subtotal Ib	95,546.0	556.5	-610.0	-3.6	+27,337.0	+159.0	122,273.0	711.9	86,411.0	503.3	8,215.0	47.8	21,882.0	127.4	618.0	3.5	5,147.0	29.9	122,273.0	711.9
Subtotal I	263,673.0	1,535.7	+4,353.0	+25.3	+308,807.0	+1,798.5	576,833.0	3,359.5	415,975.0	2,422.7	33,819.0	197.1	99,365.0	578.7	2,334.0	13.4	25,340.0	147.6	576,833.0	3,359.5
Region II:																				
Subregion IIa:																				
Minnesota	7,515.0	43.8	+90.0	+.5	+11,353.0	+66.2	18,958.0	110.5	13,043.0	76.0	969.0	5.6	3,239.0	18.9	149.0	.9	1,558.0	9.1	18,958.0	110.5
Iowa	-	-	-17.0	-.1	+11,068.0	+64.5	11,051.0	64.4	7,154.0	41.7	614.0	3.6	1,969.0	11.5	196.0	1.1	1,118.0	6.5	11,051.0	64.4
Missouri	5,931.0	34.5	-102.0	-.6	+7,851.0	+45.7	13,680.0	79.6	5,029.0	29.3	571.0	3.3	6,610.0	38.5	146.0	.8	1,324.0	7.7	13,680.0	79.6
North Dakota	4,154.0	24.2	-20.0	-.1	+1,002.0	+5.9	5,136.0	30.0	3,403.0	19.8	198.0	1.2	906.0	5.3	-	-	629.0	3.7	5,136.0	30.0
South Dakota	-	-	-53.0	-.3	+3,802.0	+22.2	3,749.0	21.9	2,537.0	14.8	73.0	.4	628.0	3.7	20.0	.1	491.0	2.9	3,749.0	21.9
Nebraska	241.0	1.4	-16.0	-.1	+3,429.0	+20.0	3,654.0	21.3	1,455.0	8.5	110.0	.6	1,423.0	8.3	113.0	.7	553.0	3.2	3,654.0	21.3
Subtotal IIa	17,841.0	103.9	-118.0	-.7	+38,505.0	+224.5	56,228.0	327.7	32,621.0	190.1	2,535.0	14.7	14,775.0	86.2	624.0	3.6	5,673.0	33.1	56,228.0	327.7
Subregion IIb:																				
Arkansas	7,480.0	43.6	+36.0	+.2	-4,779.0	-27.8	2,737.0	16.0	270.0	1.6	192.0	1.1	1,684.0	9.8	26.0	.2	565.0	3.3	2,737.0	16.0
Louisiana	82,668.0	481.4	-1,755.0	-10.2	-72,703.0	-423.4	8,210.0	47.8	449.0	2.6	2,444.0	14.2	4,338.0	25.3	47.0	.3	932.0	5.4	8,210.0	47.8
Oklahoma	32,631.0	190.1	+415.0	+2.4	-30,262.0	-176.2	2,784.0	16.3	424.0	2.5	114.0	.7	1,564.0	9.1	50.0	.3	632.0	3.7	2,784.0	16.3
Texas	226,104.0	1,317.1	+204.0	+1.2	-202,201.0	-1,177.9	24,107.0	140.4	1,027.0	6.0	3,680.0	21.5	15,633.0	91.1	42.0	.2	3,725.0	21.6	24,107.0	140.4
New Mexico	2,006.0	11.7	-36.0	-.2	+1,799.0	+10.5	3,769.0	22.0	387.0	2.3	102.0	.6	2,589.0	15.1	18.0	.1	673.0	3.9	3,769.0	22.0
Kansas	29,512.0	171.8	-334.0	-1.9	-24,022.0	-139.8	5,156.0	30.1	617.0	3.6	166.0	1.0	3,435.0	20.0	136.0	.8	802.0	4.7	5,156.0	30.1
Subtotal IIb	380,401.0	2,215.7	-1,470.0	-8.5	-332,168.0	-1,934.6	46,763.0	272.6	3,174.0	18.6	6,698.0	39.1	29,243.0	170.4	319.0	1.9	7,329.0	42.6	46,763.0	272.6
Subtotal II	398,242.0	2,319.6	-1,588.0	-9.2	-293,663.0	-1,710.1	102,991.0	600.3	35,795.0	208.7	9,233.0	53.8	44,018.0	256.6	943.0	5.5	13,002.0	75.7	102,991.0	600.3
Region III:																				
Subregion IIIa:																				
Montana	7,796.0	45.4	-48.0	-.3	-2,935.0	-17.0	4,813.0	28.1	1,108.0	6.5	225.0	1.3	2,646.0	15.4	-	-	834.0	4.9	4,813.0	28.1
Idaho	-	-	-48.0	-.3	+4,800.0	+28.0	4,752.0	27.7	2,614.0	15.2	444.0	2.6	1,067.0	6.2	-	-	627.0	3.7	4,752.0	27.7
Wyoming	6,790.0	39.6	-113.0	-.7	-3,102.0	-18.1	3,575.0	20.8	340.0	2.0	792.0	4.6	1,843.0	10.7	7.0	Neg.	593.0	3.5	3,575.0	20.8
Utah	9,313.0	54.2	-196.0	-1.1	-4,999.0	-29.1	4,118.0	24.0	826.0	4.8	249.0	1.5	2,541.0	14.8	23.0	.1	479.0	2.8	4,118.0	24.0
Colorado	3,007.0	17.5	-174.0	-1.0	+892.0	+5.3	3,725.0	21.8	610.0	3.6	182.0	1.1	1,743.0	10.2	18.0	.1	1,172.0	6.8	3,725.0	21.8
Washington	8,222.0	47.9	-195.0	-1.1	+9,082.0	+52.9	17,109.0	99.7	11,683.0	68.1	846.0	4.9	2,988.0	17.4	-	-	1,592.0	9.3	17,109.0	99.7
Oregon	384.0	2.2	-22.0	-.1	+12,686.0	+73.9	13,048.0	76.0	7,292.0	42.5	1,034.0	6.0	3,623.0	21.1	-	-	1,099.0	6.4	13,048.0	76.0
Subtotal IIIa	35,512.0	206.8	-796.0	-4.6	+16,424.0	+95.9	51,140.0	298.1	24,473.0	142.7	3,772.0	22.0	16,451.0	95.8	48.0	.2	6,396.0	37.4	51,140.0	298.1
Subregion IIIb:																				
Arizona	-	-	-1.0	Neg.	+3,394.0	+19.7	3,393.0	19.7	240.0	1.4	672.0	3.9	1,770.0	10.3	2.0	Neg.	709.0	4.1	3,393.0	19.7
Nevada	-	-	-1.0	Neg.	+2,737.0	+16.0	2,736.0	16.0	647.0	3.8	255.0	1.5	1,582.0	9.2	10.0	.1	242.0	1.4	2,736.0	16.0
California	65,008.0	378.7	-1,476.0	-8.6	-29,732.0	-173.4	33,800.0	196.7	1,665.0	9.7	4,724.0	27.5	20,798.0	121.1	90.0	.5	6,523.0	37.9	33,800.0	196.7
Subtotal IIIb	65,008.0	378.7	-1,478.0	-8.6	-23,601.0	-137.7	39,929.0	232.4	2,552.0	14.9	5,651.0	32.9	24,150.0	140.6	102.0	.6	7,474.0	43.4	39,929.0	232.4
Subregion IIIc:																				
Alaska	958.0	5.6	-18.0	-.1	+2,716.0	+15.6	3,656.0	21.1	2,084.0	12.1	214.0	1.2	780.0	4.5	197.0	1.1	381.0	2.2	3,656.0	21.1
Hawaii	1,678.0	9.8	-34.0	-.2	-132.0	-.8	1,512.0	8.8	121.0	.7	111.0	.6	836.0	4.9	37.0	.2	407.0	2.4	1,512.0	8.8
Subtotal IIIc	2,636.0	15.4	-52.0	-.3	+2,584.0	+14.8	5,168.0	29.9	2,205.0	12.8	325.0	1.8	1,616.0	9.4	234.0	1.3	788.0	4.6	5,168.0	29.9
Subtotal III	103,156.0	600.9	-2,326.0	-13.5	-4,593.0	-27.0	96,237.0	560.4	29,230.0	170.4	9,748.0	56.7	42,217.0	245.8	384.0	2.1	14,658.0	85.4	96,237.0	560.4

Neg.--Negligible.

[1] Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.

[2] Includes net foreign trade: 9,347.0 thousand barrels; 54.4 trillion Btu.

TABLE 16. - Supply and demand for residual fuel oil by major consumer sector, by States and Regions

1965

State and Region	Supply								Demand by major consumer sector											
	Refinery output		Stock change[1]		Net shipments[2]		Total supply available for consumption		Household and commercial		Industrial		Transportation		Electricity generation, utilities		Miscellaneous and unaccounted for		Total domestic demand	
	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
United States total.	268,567.0	1,688.5	-15,811.0	-99.4	333,648.0	2,097.6	586,404.0	3,686.7	156,200.0	982.0	174,900.0	1,099.6	118,020.0	741.9	114,884.0	722.4	22,400.0	140.8	586,404.0	3,686.7
Region I:																				
Subregion Ia:																				
Maine..........	-	-	-65.0	-.4	+6,511.0	+41.0	6,446.0	40.6	322.0	2.0	967.0	6.1	602.0	3.8	4,547.0	28.6	8.0	.1	6,446.0	40.6
New Hampshire...	-	-	-30.0	-.2	+2,451.0	+15.3	2,421.0	15.1	294.0	1.8	728.0	4.6	1.0	Neg.	1,375.0	8.6	23.0	.1	2,421.0	15.1
Vermont.........	-	-	-25.0	-.2	+977.0	+6.2	952.0	6.0	545.0	3.4	316.0	2.0	-	-	64.0	.4	27.0	.2	952.0	6.0
Massachusetts...	-	-	-4.0	Neg.	+53,358.0	+335.4	53,354.0	335.4	29,143.0	183.1	8,910.0	56.0	2,381.0	15.0	12,788.0	80.5	132.0	.8	53,354.0	335.4
Rhode Island....	50.0	.3	+4.0	Neg.	+6,265.0	+39.4	6,319.0	39.7	1,071.0	6.7	1,489.0	9.4	2,540.0	16.0	978.0	6.1	241.0	1.5	6,319.0	39.7
Connecticut.....	-	-	-45.0	-.3	+16,837.0	+106.0	16,792.0	105.7	4,035.0	25.4	9,560.0	60.1	454.0	2.9	2,703.0	17.0	40.0	.3	16,792.0	105.7
New York........	3,950.0	24.8	-186.0	-1.2	+99,654.0	+626.5	103,418.0	650.1	53,678.0	337.4	10,200.0	64.1	15,565.0	97.8	23,131.0	145.5	844.0	5.3	103,418.0	650.1
New Jersey......	13,128.0	82.5	+196.0	+1.2	+29,490.0	+185.4	42,814.0	269.1	7,642.0	48.0	15,668.0	98.5	6,195.0	38.9	12,628.0	79.4	681.0	4.3	42,814.0	269.1
Pennsylvania....	15,936.0	100.2	-195.0	-1.2	+27,557.0	+173.3	43,298.0	272.3	11,074.0	69.6	22,239.0	139.9	4,387.0	27.6	4,008.0	25.2	1,590.0	10.0	43,298.0	272.3
Delaware........	2,128.0	13.4	-56.0	-.4	+3,474.0	+21.9	5,546.0	34.9	505.0	3.2	3,993.0	25.1	567.0	3.6	63.0	.4	418.0	2.6	5,546.0	34.9
Maryland........	100.0	.6	+82.0	+.5	+15,320.0	+96.3	15,502.0	97.4	4,345.0	27.3	5,197.0	32.7	4,840.0	30.4	459.0	2.9	661.0	4.1	15,502.0	97.4
District of Columbia.......	-	-	-3.0	Neg.	+6,587.0	+41.4	6,584.0	41.4	6,229.0	39.2	189.0	1.2	6.0	Neg.	12.0	.1	148.0	.9	6,584.0	41.4
Virginia........	390.0	2.5	-191.0	-1.2	+16,235.0	+102.0	16,434.0	103.3	3,289.0	20.7	3,212.0	20.2	9,291.0	58.4	179.0	1.1	463.0	2.9	16,434.0	103.3
West Virginia...	30.0	.2	+5.0	Neg.	+2,082.0	+13.1	2,117.0	13.3	92.0	.6	1,899.0	11.9	-	-	72.0	.5	54.0	.3	2,117.0	13.3
North Carolina..	-	-	-309.0	-1.9	+5,302.0	+33.2	4,993.0	31.3	324.0	2.0	3,319.0	20.9	560.0	3.5	49.0	.3	741.0	4.6	4,993.0	31.3
South Carolina..	-	-	-118.0	-.7	+4,319.0	+27.1	4,201.0	26.4	340.0	2.1	1,769.0	11.1	1,265.0	8.0	32.0	.2	795.0	5.0	4,201.0	26.4
Georgia.........	70.0	.4	-232.0	-1.5	+9,084.0	+57.2	8,922.0	56.1	505.0	3.2	5,771.0	36.3	1,119.0	7.0	52.0	.3	1,475.0	9.3	8,922.0	56.1
Florida.........	-	-	-224.0	-1.4	+45,757.0	+287.7	45,533.0	286.3	342.0	2.2	8,517.0	53.5	4,577.0	28.8	27,685.0	174.1	4,412.0	27.7	45,533.0	286.3
Kentucky........	2,577.0	16.3	-92.0	-.6	-1,869.0	-11.7	616.0	4.0	10.0	.1	482.0	3.0	40.0	.3	12.0	.1	72.0	.5	616.0	4.0
Tennessee.......	188.0	1.2	-47.0	-.3	+193.0	+1.2	334.0	2.1	5.0	Neg.	203.0	1.3	21.0	.1	-	-	105.0	.7	334.0	2.1
Alabama.........	755.0	4.7	-36.0	-.2	+1,869.0	+11.8	2,588.0	16.3	80.0	.5	726.0	4.6	1,549.0	9.7	-	-	233.0	1.5	2,588.0	16.3
Mississippi.....	205.0	1.3	-26.0	-.2	+343.0	+2.2	522.0	3.3	-	-	143.0	.9	290.0	1.8	17.0	.1	72.0	.5	522.0	3.3
Ohio............	8,360.0	52.5	+38.0	+.2	+2,779.0	+17.5	11,177.0	70.2	454.0	2.9	8,891.0	55.9	610.0	3.8	98.0	.6	1,124.0	7.0	11,177.0	70.2
Subtotal Ia...	47,867.0	300.9	-1,559.0	-10.0	+354,575.0	+2,229.4	400,883.0	2,520.3	124,324.0	781.4	114,388.0	719.3	56,860.0	357.4	90,952.0	572.0	14,359.0	90.2	400,883.0	2,520.3
Subregion Ib:																				
Indiana.........	22,347.0	140.5	-676.0	-4.2	-9,032.0	-56.8	12,639.0	79.5	1,720.0	10.8	10,172.0	64.0	562.0	3.5	107.0	.7	78.0	.5	12,639.0	79.5
Illinois........	12,684.0	79.8	-75.0	-.5	+9,865.0	+62.0	22,474.0	141.3	13,421.0	84.3	8,051.0	50.6	407.0	2.6	123.0	.8	472.0	3.0	22,474.0	141.3
Michigan........	5,401.0	34.0	-46.0	-.3	+2,812.0	+17.6	8,167.0	51.3	1,322.0	8.3	5,770.0	36.3	750.0	4.7	37.0	.2	288.0	1.8	8,167.0	51.3
Wisconsin.......	1,494.0	9.4	+96.0	+.6	+1,511.0	+9.6	3,101.0	19.6	1,318.0	8.3	1,346.0	8.5	364.0	2.3	46.0	.3	27.0	.2	3,101.0	19.6
Subtotal Ib...	41,926.0	263.7	-701.0	-4.4	+5,156.0	+32.4	46,381.0	291.7	17,781.0	111.7	25,339.0	159.4	2,083.0	13.1	313.0	2.0	865.0	5.5	46,381.0	291.7
Subtotal I..	89,793.0	564.6	-2,260.0	-14.4	+359,731.0	+2,261.8	447,264.0	2,812.0	142,105.0	893.1	139,727.0	878.7	58,943.0	370.5	91,265.0	574.0	15,224.0	95.7	447,264.0	2,812.0
Region II:																				
Subregion IIa:																				
Minnesota.......	4,655.0	29.3	-280.0	-1.8	+458.0	+2.9	4,833.0	30.4	1,242.0	7.8	3,205.0	20.1	72.0	.5	298.0	1.9	16.0	.1	4,833.0	30.4
Iowa............	-	-	-13.0	-.1	+558.0	+3.6	545.0	3.5	303.0	1.9	142.0	.9	14.0	.1	28.0	.2	58.0	.4	545.0	3.5
Missouri........	1,058.0	6.7	+28.0	+.2	+2,245.0	+14.0	3,331.0	20.9	1,806.0	11.4	1,230.0	7.7	148.0	.9	4.0	Neg.	143.0	.9	3,331.0	20.9
North Dakota....	600.0	3.8	-13.0	-.1	+248.0	+1.6	835.0	5.3	220.0	1.4	589.0	3.7	24.0	.2	-	-	2.0	Neg.	835.0	5.3
South Dakota....	-	-	-4.0	Neg.	+52.0	+.3	48.0	.3	20.0	.1	2.0	Neg.	1.0	Neg.	25.0	.2	-	-	48.0	.3
Nebraska........	75.0	.5	-5.0	Neg.	+241.0	+1.5	311.0	2.0	58.0	.4	53.0	.3	105.0	.7	93.0	.6	2.0	Neg.	311.0	2.0
Subtotal IIa..	6,388.0	40.3	-287.0	-1.8	+3,802.0	+23.9	9,903.0	62.4	3,649.0	23.0	5,221.0	32.7	364.0	2.4	448.0	2.9	221.0	1.4	9,903.0	62.4
Subregion IIb:																				
Arkansas........	1,045.0	6.6	-118.0	-.7	-499.0	-3.2	428.0	2.7	-	-	347.0	2.2	35.0	.2	6.0	Neg.	40.0	.3	428.0	2.7
Louisiana.......	14,815.0	93.1	-518.0	-3.3	-6,541.0	-41.1	7,756.0	48.7	4.0	Neg.	399.0	2.5	7,029.0	44.2	22.0	.1	302.0	1.9	7,756.0	48.7
Oklahoma........	1,537.0	9.7	-132.0	-.8	-595.0	-3.7	810.0	5.2	12.0	.1	534.0	3.4	235.0	1.5	2.0	Neg.	27.0	.2	810.0	5.2
Texas...........	39,590.0	248.9	-1,784.0	-11.1	-23,534.0	-148.0	14,272.0	89.8	54.0	.3	1,412.0	8.9	11,893.0	74.8	8.0	.1	905.0	5.7	14,272.0	89.8
New Mexico......	360.0	2.3	+2.0	Neg.	+986.0	+6.1	1,348.0	8.4	30.0	.2	9.0	.1	35.0	.2	22.0	.1	1,252.0	7.8	1,348.0	8.4
Kansas..........	849.0	5.3	-121.0	-.8	+425.0	+2.7	1,153.0	7.2	129.0	.8	532.0	3.3	132.0	.8	175.0	1.1	185.0	1.2	1,153.0	7.2
Subtotal IIb..	58,196.0	365.9	-2,671.0	-16.7	-29,758.0	-187.2	25,767.0	162.0	229.0	1.4	3,233.0	20.4	19,359.0	121.7	235.0	1.4	2,711.0	17.1	25,767.0	162.0
Subtotal II.	64,584.0	406.2	-2,958.0	-18.5	-25,956.0	-163.3	35,670.0	224.4	3,878.0	24.4	8,454.0	53.1	19,723.0	124.1	683.0	4.3	2,932.0	18.5	35,670.0	224.4
Region III:																				
Subregion IIIa:																				
Montana.........	2,016.0	12.7	-156.0	-1.0	-595.0	-3.7	1,265.0	8.0	504.0	3.2	322.0	2.0	313.0	2.0	-	-	126.0	.8	1,265.0	8.0
Idaho...........	-	-	-	-	+345.0	+2.1	345.0	2.1	172.0	1.1	117.0	.7	53.0	.3	1.0	Neg.	2.0	Neg.	345.0	2.1
Wyoming.........	4,266.0	26.8	-117.0	-.7	-1,987.0	-12.5	2,162.0	13.6	282.0	1.8	618.0	3.9	1,130.0	7.1	29.0	.2	103.0	.6	2,162.0	13.6
Utah............	4,164.0	26.3	-14.0	-.1	+1,352.0	+8.5	5,502.0	34.7	597.0	3.8	3,219.0	20.2	94.0	.6	1,584.0	10.0	8.0	.1	5,502.0	34.7
Colorado........	1,147.0	7.2	+47.0	+.3	+782.0	+4.9	1,976.0	12.4	559.0	3.5	684.0	4.3	687.0	4.3	19.0	.1	27.0	.2	1,976.0	12.4
Washington......	11,286.0	70.8	-1,143.0	-7.2	-392.0	-2.5	9,751.0	61.1	3,554.0	22.3	3,105.0	19.5	1,390.0	8.7	23.0	.1	1,679.0	10.5	9,751.0	61.1
Oregon..........	1,026.0	6.5	-109.0	-.7	+4,333.0	+27.2	5,250.0	33.0	2,445.0	15.4	1,577.0	9.9	645.0	4.1	5.0	Neg.	578.0	3.6	5,250.0	33.0
Subtotal IIIa.	23,905.0	150.3	-1,492.0	-9.4	+3,838.0	+24.0	26,251.0	164.9	8,113.0	51.1	9,642.0	60.5	4,312.0	27.1	1,661.0	10.4	2,523.0	15.8	26,251.0	164.9
Subregion IIIb:																				
Arizona.........	-	-	-2.0	Neg.	+53.0	+.3	51.0	.3	26.0	.2	1.0	Neg.	-	-	4.0	Neg.	20.0	.1	51.0	.3
Nevada..........	-	-	-1.0	Neg.	+86.0	+.5	85.0	.5	56.0	.4	18.0	.1	7.0	Neg.	-	-	4.0	Neg.	85.0	.5
California......	87,207.0	548.2	-8,789.0	-55.2	-10,531.0	-66.1	67,887.0	426.9	1,746.0	11.0	15,407.0	96.9	33,820.0	212.6	16,410.0	103.2	504.0	3.2	67,887.0	426.9
Subtotal IIIb.	87,207.0	548.2	-8,792.0	-55.2	-10,392.0	-65.3	68,023.0	427.7	1,828.0	11.6	15,426.0	97.0	33,827.0	212.6	16,414.0	103.2	528.0	3.3	68,023.0	427.7
Subregion IIIc:																				
Alaska..........	1,026.0	6.4	-103.0	-.6	-36.0	-.2	887.0	5.6	199.0	1.3	563.0	3.5	64.0	.4	18.0	.1	43.0	.3	887.0	5.6
Hawaii..........	2,052.0	12.8	-206.0	-1.3	+6,463.0	+40.6	8,309.0	52.1	77.0	.5	1,088.0	6.8	1,151.0	7.2	4,843.0	30.4	1,150.0	7.2	8,309.0	52.1
Subtotal IIIc.	3,078.0	19.2	-309.0	-1.9	+6,427.0	+40.4	9,196.0	57.7	276.0	1.8	1,651.0	10.3	1,215.0	7.6	4,861.0	30.5	1,193.0	7.5	9,196.0	57.7
Subtotal III	114,190.0	717.7	-10,593.0	-66.5	-127.0	-.9	103,470.0	650.3	10,217.0	64.5	26,719.0	167.8	39,354.0	247.3	22,936.0	144.1	4,244.0	26.6	103,470.0	650.3

Neg.--Negligible.
[1]Withdrawals from stocks add to supply and are indicated by plus signs; additions to stocks reduce supply and are indicated by minus signs.
[2]Includes net foreign trade: 329,727.0 thousand barrels; 2,073.0 trillion Btu.

APPENDIX

TABLE A-1. - Outline of computational procedures and source data for supply and demand sectors

(The references in this table are to Bureau of Mines' publications, especially the Minerals Yearbook (MYB), Volume II (Volume I-II after 1966); and to a series of periodic reports, Mineral Industry Surveys (MIS))

Item, by table boxhead	Computation	References
	TABLES 1 AND 3	
Crude oil:		
Production	Reported directly from available State data	MYB 1961, table 8, pp. 369-370. MYB 1966, table 6, pp. 818-820.
Stock change	Difference between stock on hand Jan. 1 and stock on hand Dec. 31. For purposes of this study, a withdrawal from stock is regarded as adding to the supply available for consumption; additions to stock are considered to decrease the supply available for consumption.	MYB 1960, table 36, p. 407. MYB 1965, table 30, p. 391.
Net shipments	Difference between total supply of crude oil available for consumption (runs to stills) and production plus or minus stock change less losses and transfers for use as crude oil.	
Net foreign trade	Difference between imports and exports. State data included in net shipments. (Shown in footnote to tables.)	MYB 1960, table 1, p. 362. MYB 1965, table 1, p. 350.
Losses and transfers for use as crude.	The sum of the following items: refinery fuel use and losses, available by State; estimated State breakdown of transfers to distillate and residual fuel oil, which are published by refinery district and U.S. totals; estimated State breakdown of other fuel in losses shown in supply and demand, MYB table.	MYB 1960, table 32, p. 400; table 61, p. 446; table 65, p. 451. MYB 1961, table 57, p. 431. MYB 1965, table 17, p. 378; table 54, p. 428; table 57, p. 431. MYB 1966, table 4, p. 816.
Runs to stills:		
Total supply of crude oil.	Total crude runs to stills published by major States. Breakdown of combined States estimated.	MYB 1960, table 32, p. 400. MYB 1965, table 17, p. 378.
Transfers in of natural gas liquids (component of runs to stills).	Refinery district and U.S. total data available. State breakdown estimated.	MYB 1960, table 46, p. 442. MYB 1965, table 42, p. 412.
Total refinery output	Sums of total supply of crude oil plus transfers in of natural gas liquids.	
Unfinished oils, net	Refinery district and U.S. total data available. State breakdown estimated.	MYB 1960, table 46, p. 423. MYB 1965, table 42, p. 412.
Overage or loss	Refinery district and U.S. total data available. State breakdown estimated.	MYB 1960, table 46, p. 423. MYB 1965, table 42, p. 412.
Refined products:		
Total supply of refined products.	Refinery output, plus unfinished oils, net, plus or minus overage or loss.	
Stock change	Sum of stock changes of six major products computed for tables 5-10 for 1960, tables 11-16 for 1965--includes an unaccounted for item to add to published national total.	
Transfers in of natural gas liquids (component available to consumer).	Total U.S. shipments of natural gas liquids less deliveries to refineries. No data on shipments by States are available. State figures were estimated.	MYB 1960, table 6, p. 344; table 7, p. 345. MYB 1965, table 1, p. 324.

TABLE A-1. - Outline of computational procedures and source data for supply and demand sectors--Continued

Item, by table boxhead	Computation	References
TABLES 1 AND 3--Continued		
Refined products--(Con.):		
Net shipments (U.S. total is the same as net foreign trade).	State figures are the sum of net shipments of six major products computed for tables 5-10 for 1960, tables 11-16 for 1965. An unaccounted for item is shown to balance the national total.	
Net foreign trade......	Difference between imports and exports. State data included in net shipments. (Shown in footnote to tables)	MYB 1961, table 1, p. 358. MYB 1965, table 1, p. 350.
Losses, gains, and unaccounted for.	A balancing item published in the national totals of unknown distribution.	IC 8384, table 5, p. 72.[1]
Total supply available for consumption.	Total supply of refined products plus or minus stock change (including natural gas liquids) plus or minus net shipments equals total supply available for consumption.	
TABLES 2 AND 4		
Major products..........	The major petroleum products account for 88 percent of the apparent total domestic demand.	Tables 5-16 of this I.C.
Miscellaneous products unaccounted for.	This column is needed to account for the additional 12 percent of demand. It is the difference between the sum of the major products totals (tables 5-10 for 1960, and 11-16 for 1965) and the "Total supply available for consumption" of tables 1 (1960) and 3 (1965).	
Apparent total domestic demand.	The sum of the major products total and miscellaneous products unaccounted for.	
TABLES 5 THROUGH 16		
Supply:		
Refinery output........	Refinery output data by product is published. State breakdown is estimated. Note: Tables 5 and 11 also include liquefied gases produced at natural gas processing plants.	MYB 1960, table 9, p. 346; table 45, p. 421. MYB 1965, table 9, p. 335; table 41, p. 411.
Stock change...........	Difference between refinery stock on hand Jan. 1 and stock on hand Dec. 31 for each product. Published by district for each product. State breakdown estimated with the exception of liquefied petroleum gases. Bulk terminal stock by State estimated.	MYB 1960, table 58, p. 443; table 61, p. 446; table 65, p. 451; table 71, p. 459. MYB 1965, table 51, p. 425; table 54, p. 428; table 57, p. 431; table 59, p. 433. MIS NGR-300, Dec. 1959, p. 2. MIS NGR-312, Dec. 1960, p. 2. MIS NGL, Dec. 1964, p. 2. MIS NGL, Dec. 1965, p. 2.
Net shipments..........	Difference between refinery output plus or minus stock change and total supply available for consumption. In the case of tables 5 and 11, input at refineries also are involved.	
Net foreign trade......	Discrepancy of supply-demand data results in tables 6, 10, and 14 having net foreign trade figures in excess of the net shipments figures. These figures are shown in footnotes and do not add to total supply.	MYB 1960, table 41, p. 414. MYB 1965, table 38, p. 406.
Input at refineries....	Special category (tables 5 and 11) of liquefied gases (estimated) to eliminate duplication of LPG-runs to stills.	

See footnotes at end of table.

TABLE A-1. - Outline of computational procedures and source data for supply and demand sectors--Continued

Item, by table boxhead	Computation	References
	TABLES 5 THROUGH 16--Continued	
Supply--(Con.):		
Total supply available for consumption.	This column equates to the total domestic demand column.	
Demand by major consuming sector:		
Household and commercial.	Liquefied gases: Domestic and commerical. Kerosine: Range oil. Distillate fuel oil: Range oil and heating oil--distillate. Residual fuel oil: Used as heating oil.	MIS MMS 3297, 1960, p. 3. MIS, Ship.-LPG and E-1965, p. 4.[1] MIS MMS 3214, 1960, pp. 5-7. MIS, Ship.-FO and K-1965, pp. 4-6.[2]
Industrial............	Liquefied gases: Industrial, refinery fuel, gas manufacturing, and chemical use. Kerosine: Tractor fuel and other uses. Distillate fuel oil: Industrial (excluding oil company fuel) plus oil company fuel.	MIS MMS 3297, 1960, pp. 3-4. MIS, Ship.-LPG and E-1965, pp. 4, 10.[2] MIS MMS 3284, 1960, pp. 4, 6, 8, 10. MIS, Ship.-FO and K-1965, pp. 4, 7, 8.[2]
Transportation.........	Liquefied petroleum gas: Internal combustion. Jet fuel: Demand for jet fuel. Gasoline: Total consumption (adjusted). Kerosine: Commercial jet fuel. Distillate fuel oil: Miscellaneous uses--diesel on highways, military vessels bunkering, and railroads. Residual fuel: Military use, vessel bunkering, and railroads.	MIS MMS 3297, 1960, p. 3. MIS, Ship.-LPG and E-1965, p. 4.[2] MIS MMS 3284, 1960, pp. 4, 12-15. MIS, Sales-FO and K-1965, p. 4, 10-13.[3] MYB 1960, table 52, p. 433. MYB 1965, table 48, p. 420.
Electricity generation, utilities.	Distillate fuel oil. Residual fuel oil.	MIS MMS 3284, 1960, p. 11. MIS, Ship.-FO and K-1965, p. 9.[4]
Miscellaneous and unaccounted for.	Liquefied petroleum gas: all other. Distillate fuel oil. Residual fuel oil.	MIS MMS 3297, 1960, p. 4. MIS, Ship.-LPG and E-1965, p. 4.[2] MIS MMS 3284, 1960, p. 15. MIS, Ship.-FO and K-1965, p. 13.[4]
Total domestic demand..	Sum of Household and commercial, Industrial, Transportation, Electricity generation, utilities, Miscellaneous and unaccounted for.	

[1]Morrison, Warren E., and Charles L. Readling. An Energy Model for the United States, Featuring Energy Balances for the Years 1947 to 1965 and Projections and Forecasts to the Years 1980 and 2000. BuMines Inf. Circ. 8384, July 1968, 127 pp.
[2]Shipments of Liquefied Petroleum Gases and Ethane in 1965, Annual.
[3]Sales of Fuel Oil and Kerosine in 1965, Annual.
[4]Shipments of Fuel Oil and Kerosine in 1965, Annual.

☆ U.S. GOVERNMENT PRINTING OFFICE : 1969 O - 347-513

IC bureau of mines information circular 8412

PREPARATION OF ANHYDROUS ALUMINUM CHLORIDE

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

June 1969

PREPARATION OF ANHYDROUS ALUMINUM CHLORIDE

By Robert L. de Beauchamp

* * * * * * * * * * * information circular 8412

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

de Beauchamp, Robert L
Preparation of anhydrous aluminum chloride. [Washington] U. S. Dept. of the Interior, Bureau of Mines [1969]

19 p. illus., tables. (U. S. Bureau of Mines. Information circular 8412)

Includes bibliography.

1. Aluminum chloride. I. Title. II. Title: Anhydrous aluminum chloride. (Series)

TN23.U71 no. 8412 622.06173

U. S. Dept. of the Int. Library

CONTENTS

ILLUSTRATION

TABLES

PREPARATION OF ANHYDROUS ALUMINUM CHLORIDE

by

Robert L. de Beauchamp[1]

ABSTRACT

The Bureau of Mines reviewed aluminum chloride technology to determine the problems associated with its preparation from minerals, and to ascertain the best areas for research to solve these problems. Commercial $AlCl_3$ production processes are described and the "state of the art" for the preparation of $AlCl_3$ from aluminous materials is evaluated. Areas for further research are indicated.

INTRODUCTION

The Bureau of Mines' aluminum program includes the investigation of alternate processes of producing aluminum from ores. The electrowinning of aluminum by the electrolysis of aluminum chloride ($AlCl_3$) in molten salt electrolytes (41)[2] has been proposed as a possible alternate to the Bayer-Hall process for producing aluminum.

One phase of this investigation was to survey and evaluate previous research on the preparation of anhydrous $AlCl_3$, to determine the problems associated with its preparation from minerals, and to ascertain the best areas for research to solve these problems. To accomplish this, a survey of the technical literature was made and a bibliography compiled of journal references and both domestic and foreign patents relating to the preparation of $AlCl_3$. In addition, visits were made to three commercial manufacturers of $AlCl_3$ to become acquainted with their current manufacturing technology.

Manufacture of $AlCl_3$ from aluminous materials is not a new technology, but has been known and practiced for at least 140 years. The history of the preparation of $AlCl_3$ has been thoroughly and adequately covered by both Ralston (38) and Thomas (47).

---

[1] Research chemist, Boulder City Metallurgy Research Laboratory. Bureau of Mines, Boulder City, Nev.

[2] Underlined numbers in parentheses refer to items in the list of references at the end of this report.

The total U.S. production of anhydrous $AlCl_3$ for 1966 was only about 35,000 tons. Economics in this country favor the preparation of $AlCl_3$ from scrap metal rather than from aluminum oxide (Al_2O_3) materials because plant investment and operating costs are much lower for using scrap. A larger annual production of $AlCl_3$ would be needed for the difference in raw material costs to offset the higher plant investment and operating costs of the Al_2O_3 process.

The use of oxide materials is more prevalent in Europe because of lower labor costs, unavailability of aluminum scrap, or in some cases, a desire to utilize domestic ores.

COMMERCIAL $AlCl_3$ PROCESSES

$AlCl_3$ From Aluminum Metal

The preparation of $AlCl_3$ by the chlorination of scrap aluminum metal is accomplished in a relatively simple apparatus (fig. 1). The reactor consists of a bathtub-like structure made of sheet steel with a high-alumina ceramic lining to protect the steel. The reactor-tub is divided across the middle by a ceramic bridge which separates the feed compartment from the reaction

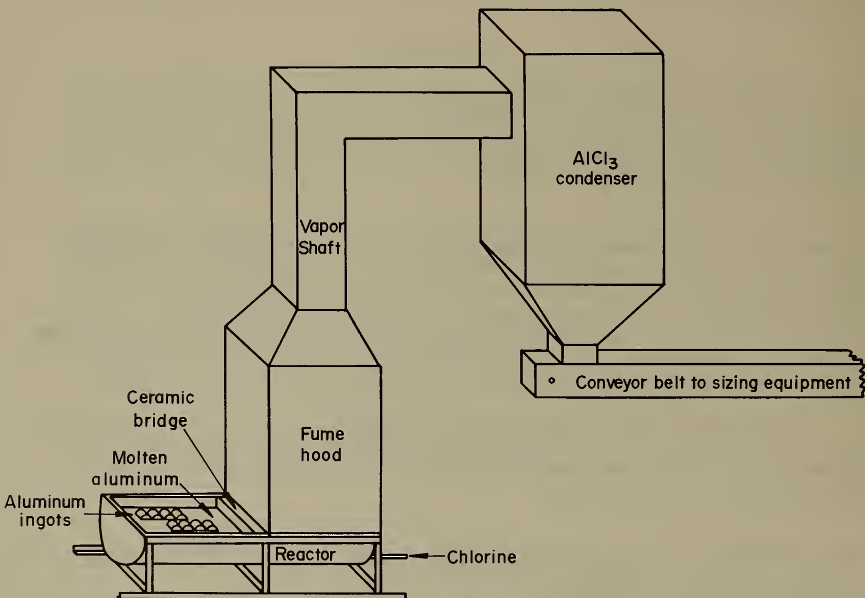


FIGURE 1. - Schematic Drawing of Apparatus for Preparing $AlCl_3$ From Aluminum Metal.

compartment. In starting, molten aluminum is poured into the reactor until the level of the molten metal is above the bottom of the bridge. Chlorine gas is introduced through nickel pipes that pass through the bottom or lower sides of the reaction compartment into the molten aluminum. The top of the reaction compartment is enclosed by a ceramic-lined metal shaft that carries off the $AlCl_3$ vapor which is prevented from passing into the feed compartment by the bridge. The $AlCl_3$ vapor is conducted to a rectangular sheet steel condensing bin where it deposits on the walls which are air-cooled. At intervals the sides of the condenser are jarred with hammers to knock down the deposits into the funnel-shaped bottom where they are conveyed to sizing and packaging equipment.

The reactor temperature is controlled by water-cooling the sides of the reactor, by regulating the chlorine feed rate, or by making small additions of copper or magnesium, to lower the melting point of the aluminum metal. Ingots of feed aluminum are preheated and are then submerged gently in the molten metal. The heat of reaction provides all of the heat necessary to keep the bath molten and to melt fresh feed as it is used up.

The $AlCl_3$ product ranges in color from yellow (excess chlorine) to white or grey (contains condensed aluminum vapor). The purity of the product is controlled by the purity of the feed material. Small amounts of iron are usually present due to corrosion of the equipment. Large amounts (over 1 percent) show up as an orange-colored product.

$AlCl_3$ From Oxide Materials

Processes for manufacturing $AlCl_3$ from oxide materials, developed during the past 10 years, have been reported in journal and patent literature of the United States (12), Great Britain (21), West Germany (22), the U.S.S.R. (8, 20, 36), Rumania (13), and India (3, 39).

At least two of these processes were used commercially and are described as follows:

Gulf Process

In 1920 the Gulf Oil Company (34) began manufacture of $AlCl_3$ (under the tradename Alchlor) primarily for captive use in petroleum refining and discontinued its manufacture in 1960 when better catalysts were developed, particularly for use in manufacturing lubricating oils.

The basic process for manufacturing $AlCl_3$ consisted of the following steps:

1. Bauxite and coke were ground, mixed, and calcined in a rotary kiln at 830° to 870° C to remove free and combined water and to fully carbonize the coke.

2. The hot calcine was stored in a hot bin and fed intermittently at 4-hour intervals to the reaction retorts.

3. A mixture of chlorine and oxygen was fed continuously to the bottom of the retorts, except when charging. The gas feed rate was regulated so that no unreacted chlorine left the retort with the $AlCl_3$ vapor.

4. The $AlCl_3$ vapor from the top of the reactor was led to a condenser where it deposited on the walls and was continuously scraped off into barrels.

Process Improvements

Over the 40-year period of operation many improvements in the process were made and many patents filed on them. Some of the variations and improvements to the various parts of the process are described as follows:

1. Feed Preparation. The bauxite used contained about 2 to 3 percent free moisture and about 30 percent combined water. Calcination of the bauxite to remove moisture prior to chlorination was done both separately and combined with carbonaceous materials (coke, coal, asphalt, etc.). The calcination temperature was held to 770° C in order to obtain maximum chlorine reactivity of the feed. Calcination at higher temperatures resulted in converting the alumina in the bauxite to α-Al_2O_3 which is less reactive to chlorine. The rotary gas-fired kiln used was of brick-lined steel 6 feet OD by 60 feet long, and revolved at 1 rpm.

Earlier practice required mixing calcined bauxite, coke, and wax tailings, pressing the mixture into briquets, and roasting the briquets. Briquetting was later discarded.

2. Reactor Design. Many reactor designs were tried and discarded. Early reactors used a vertical shaft furnace with concurrent flow (gas flow and feed from top to bottom, product vapor discharged at bottom). One reactor was operated at 15 to 30 psi so that the product vapor could be cooled and a liquid $AlCl_3$ product tapped off. A shelf-type shaft furnace was devised with feed flow downward and gas flow upward. The final design was a cylindrical shaft furnace with a conical taper at both top and bottom. The flow was countercurrent (feed downward, gases upward) and the product vapor was conducted first to a cooler and then to condensers.

One of the main problems encountered with the reactors was the rapid erosion of the furnace lining by the reaction gases at high temperatures. Many methods were tried to slow the erosive action such as cooling the shaft walls and grading the feed bed so that the reaction occurred at the more permeable bed center and as far from the walls as possible. The walls of the reactor were made mainly of firebrick.

A cooler made of steel with a brick lining was air-cooled and placed between the reactor and condenser in order to lower the product vapor temperature from 870° to 650° C. The condenser was made of two vertical water-jacketed 6-inch steel pipes. Each pipe had an internal scraper mechanism which continuously scraped the deposited $AlCl_3$ into steel drums.

Aluminum Chloride Product

No provision was made for product purification. An average analysis of the product was as follows, in percent: $AlCl_3$ - 95.0, Al_2O_3 - 2.21, $FeCl_3$ - 1.34, $TiCl_4$ - 0.88, and SiO_2 - 0.11.

The net cost for producing 32,000 pounds per day in 1958 (last full year of normal production) was 11.44 cents per pound.

Table 1 shows the long-time average raw material charge used in producing Alchlor in comparison with the theoretical charges. Table 2 shows the operating costs. The labor force included 33 skilled and 25 unskilled men.

TABLE 1. - Long-time average raw material charge in comparison with the theoretical charges, pounds[1]

Raw material	Actual	Theoretical
Bauxite to kiln....................	0.71	0.64
Petroleum coke to kiln..............	.39	.20
Chlorine to retorts.................	1.01	.75
Oxygen to retorts...................	.14	.14

[1] To produce 1 pound of Alchlor.

TABLE 2. - Operating costs, cents per pound Alchlor

Supervision and operating labor......................	4.25
Maintenance:	
Labor..	3.61
Material.......................................	1.55
Fuel (for tail gas incinerator and kiln).............	.14
Power (2.5 kwhr/lb Alchlor)..........................	1.90
Steam (2 lb/lb Alchlor)..............................	.77
Salt...	.45
Bauxite..	1.04
Coke...	.23
Miscellaneous..	.86
Total..	14.80
Credit for caustic (2.87 cents/lb)...............	3.36
Net cost.....................................	11.44

"Badische Anilin und Soda Fabrik" Process

This process, described by Hille and Dürrwächter (22), involved manufacture of $AlCl_3$ from both bauxite and Bayer alumina.

The chlorination of bauxite was accomplished in a shaft furnace according to the method of Carl Wurster (53). Carbon monoxide and chlorine were heated to the reactor temperature (900° C) in a beechwood charcoal contactor which partially converted the gases to phosgene. The hot gases were passed through

the bauxite inside the reactor that converted the Al_2O_3 to $AlCl_3$. The heats of reaction shown in the following equations were sufficient to sustain the reaction when the reactor was the proper size and properly insulated:

$$3\ CO + 3\ Cl_2 \rightleftarrows 3\ COCl_2 \qquad \Delta H_{18^\circ\ C} = -75.75\ Kcal \qquad (1)$$

$$Al_2O_3 + 3\ COCl_2 \rightleftarrows 2\ AlCl_3 + 3\ CO_2 \qquad \Delta H_{18^\circ\ C} = -80.68\ Kcal \qquad (2)$$

$$Al_2O_3 + 3\ Cl_2 + 3\ CO \rightleftarrows 2\ AlCl_3 + 3\ CO_2 \qquad \Delta H_{18^\circ\ C} = -156.43\ Kcal \qquad (3)$$

The iron, alkali, and alkaline earth metals present in bauxites aided the chlorination by acting as catalysts. Part of the impurities in the bauxite carried over into the product as volatile chlorides and required a purification step in order to obtain a pure product.

The chlorination of γ-Al_2O_3 was accomplished in a fluosolids reactor using a mixture of CO and chlorine passed through a beechwood-charcoal contactor to form phosgene (400° C). The three-phase fluidized bed operating at 600° C consisted of alumina, gas, and finely dispersed $NaAlCl_4$ catalyst added to the bed. A pumice filter, located above the reactor, trapped the $NaAlCl_4$ in the product vapor and returned it to the reactor by gravity flow. The vapor was cooled in a condenser from which the crystallized product was collected into drums.

At a ratio of 110 g of $NaAlCl_4$ per 100 g of γ-Al_2O_3, a maximum catalytic effect was obtained. The use of this catalyst caused a sharp reactivity increase between 400° and 500° C, but the reactivity remained constant between 550° and 900° C.

To obtain optimum chlorination of the Al_2O_3, careful control of the feed material preparation was necessary. Precipitation of the Bayer alumina hydrate and calcination of the hydrate (at 1,000° C) were the two main areas of control necessary for obtaining the required γ-alumina quality.

EVALUATION OF THE OXIDE PROCESS

Raw Materials

The raw materials that may be used for the preparation of $AlCl_3$ include bauxite, clays, shale, anorthosite, coal ash, and many other aluminum-containing materials. Pure Bayer process Al_2O_3 may also be used if its higher cost can be justified by processing costs sufficiently lower than those incurred with the impure feed materials. Bauxite or clays are the most logical choices because of their higher Al_2O_3 contents and the large reserves of these materials available. Iron is the impurity most deleterious to the process since it uses up chlorine and is difficult to remove from the product. Other chlorine-consuming impurities encountered are silicon, titanium, manganese, magnesium, and calcium.

Dehydration of Aluminous Materials

Prior to chlorination, aluminous materials, which may contain up to 35 percent free and combined water in the case of bauxite, must be calcined to remove their moisture. Any moisture left in the feed material would carry over with the product and degrade it. If all the water is removed by calcining at 1,200° C, the Al_2O_3 is converted to α-Al_2O_3, which is more resistant to chlorination than Al_2O_3 dehydrated at lower temperatures.

Thermal decomposition of the monohydrates and trihydrates of Al_2O_3 between 200° and 1,100° C forms a number of metastable aluminas which retain between 0 and 0.5 mole of water per mole of Al_2O_3. The older terminology referred to these as "γ-alumina," whereas today they are referred to as "transition aluminas." Recent investigators (46) have identified seven transition aluminas (six of them crystalline) and labeled them "ρ-, χ-, ν-, γ-, κ-, θ-, and δ-aluminas."

When the α- and β-aluminum trihydrates are dehydrated in air at 300° to 400° C, χ and η forms are obtained which have a surface area of 400 to 500 m^2/g, mainly localized in pores with a diameter of less than 40 A. The χ- and η-aluminas are the essential constituents of activated aluminas (26). The specific surface areas of the χ-, η-, and γ-aluminas decrease progressively as the temperature of the treatment increases; the κ-, θ-, and δ-aluminas that are subsequently obtained have surfaces not exceeding some tens of square meters per gram.

It is suspected that the ease of chlorination of the different transition aluminas is proportional to their surface area and to some extent their pore size. One would expect the "activated aluminas" to be the most easily chlorinated.

Much of the technology concerning the calcination of aluminous materials prior to chlorination was developed over the years by empirical methods. Since aluminous ores vary considerably in their composition and frequently carbonaceous reductants were mixed with the ores during calcination, the results obtained by different investigators did not always agree. Detailed mineral, chemical, and physical identification of the starting materials and of the calcine were seldom reported by the investigators. Most descriptions were given only in very general terms. Some examples follow:

1. Adadurov (1) reported that the best temperature for calcining clay (percentages of Fe_2O_3 and kaolinite given) is about 600° to 750° C. At this temperature there is formed at a commercially satisfactory rate kaolinite anhydride, 2 $SiO_2 \cdot Al_2O_3$. At 900° C, the free oxides, 2 SiO_2 and Al_2O_3, are formed, while at 1,000° C, sillimanite ($Al_2O_3 \cdot SiO_2$) is formed; these are chlorinated with difficulty and lower the yield.

2. McAfee (35) in a patent states:

> . . . crude bauxite is dehydrated in a rotating kiln at a temperature of about 1,800° F (980° C). No preliminary processing of the crude bauxite is required beyond crushing such lumps as may be present to a size which will permit ready calcination. It is difficult to calcine bauxite in a rotating kiln in lumps larger than one-inch cross-section.

3. Culberson (12) in a patent states:

> Bauxite of the analysis given in our first specific example, when calcined at a maximum temperature of 1,600° F (870° C) had a pore surface area of 121 square meters per gram.
>
> Aggregate prepared by the process described and claimed herein (coking bauxite with asphalt), and carbonized at 1,600° F (870° C) had a pore surface area of 206 square meters per gram. This pore surface area is 70 percent greater than that of bauxite calcined alone.

The Culberson patent gave more specific information on the raw and calcined feed material than found in any other reference. Another example from the same patent is as follows:

> . . . identical samples of our aggregates (coked bauxite) were maintained for a period of 16 hours in an atmosphere of nitrogen at temperatures of 1,550° F (842° C), 1,800° F (980° C), 2,100° F (1,148° C), and 2,400° F (1,315° C). X-ray diffraction patterns of these samples indicated the presence of only alpha Al_2O_3 in the samples which had been maintained at 2,100° F (1,148° C) and at 2,400° F (1,315° C). The sample maintained at 1,800° F (980° C) comprised alpha Al_2O_3 and some transition form of Al_2O_3 between the gamma and alpha forms. The sample of Al_2O_3 heated at 1,550° F (842° C) was principally of the gamma and chi forms. The alpha form of alumina is of very low reactivity, and the reactivity increases sharply through the gamma and chi forms.

Chlorination

Temperatures

Most chlorination of aluminous materials has been done with chlorine. Hydrogen chloride will chlorinate alumina at about 1,200° C; however, the reaction does not go to completion because the byproduct water vapor hydrolyzes some of the $AlCl_3$ back to Al_2O_3 until an equilibrium is established (47).

The addition of carbon to the Al_2O_3 accelerates its reaction with HCl by combining with the oxygen and preventing the formation of water vapor. With carbon, a 35-percent conversion of the alumina with HCl will occur at 1,000° C in 1 hour at an HCl velocity of 11.5 liters per hour.

According to Spitzin and Gwosdewa (42) a mixture of HCl and chlorine is more efficient for the production of $AlCl_3$ from clay or Al_2O_3 than either gas alone. Chlorine and HCl mixtures react appreciably with alumina-carbon mixtures at 500° C and yields are excellent in the range 500° to 600° C. Chlorine, carbon, and Al_2O_3 react appreciably at 800° to 900° C, whereas HCl, carbon, and alumina require 1,000° C. The action of chlorine on Al_2O_3 without a reductant is negligible until about 1,200° C.

Of the impurities commonly associated with aluminous materials, Fe_2O_3 chlorinates at 600° C without carbon, and at 200° C with carbon (54). Without carbon SiO_2 chlorinates at 1,200° C (42); however, with carbon the reaction begins at 600° C and is accelerated at about 800° C (43).

Reductants

The carbon reductant can be added to the chlorination reaction in several ways. Calcined ore, coke, and a binder (asphalt or wax tailings) can be made into briquets, coked, and chlorinated (34). This method provided a porous material that chlorinates easily. A method requiring less labor would be to calcine ground ore and coke and feed them hot into the reactor for chlorination (32).

Another means of providing a reductant is to use CO along with the chlorine. Passing these gases through an activated charcoal contactor at 125° to 150° C converts them to phosgene. Chlorination with $COCl_2$ is more rapid than with mixtures of CO and chlorine (48). The reaction of CO with Cl_2 liberates 75.75 kcal/mole of reactants which helps to make the chlorination of bauxite or alumina self-sustaining in respect to reaction temperature.

Some processes (32) add air, oxygen, or air-oxygen mixtures to the reacting gases in order to form CO or CO_2 with coke in the charge. This provides additional reaction heat with which to maintain the operating temperature.

Catalysts

Certain impurities in the aluminous ores such as sodium or potassium salts (2, 40) act as catalysts in the chlorination reaction. When using a pure alumina feed, addition of molten $NaAlCl_4$ to the reactants will increase the yield of $AlCl_3$ (22).

Reactor Design

The three main types of reactors that appear applicable to the manufacture of $AlCl_3$ from aluminous materials are the shaft furnace, the fluosolids reactor, and the horizontal rotary kiln. The shaft furnace would be best with ores using either gaseous or solid reductants. The fluid bed reactor has been used successfully with a carefully prepared and graded γ-alumina. Milled ores

would probably be too variable in their physical properties to be used successfully in the fluid-bed reactor; however, only actual practice could determine this conclusively. The horizontal rotary kiln has many favorable characteristics, but the combination of abrasion with the highly corrosive gases (chlorine plus reductant) would probably require too frequent replacement of the kiln lining and the shell itself.

Many designs and configurations of shaft furnaces have been tried (5, 31-33, 35). Apparently, the most frequently used design is a raw material feed from the top with an upward countercurrent flow of gases from the bottom. The product vapor would be drawn off the top. The operating temperature of the reactor would be about 900° C. The furnace lining should be a dense, high-temperature, heavy-duty, fire-clay brick. Such brick is used in blast furnaces and in furnaces for the chlorination of rutile. To retain as much reaction heat as possible so that the reaction will be self-sustaining, the furnace lining must be backed up with sufficient insulating brick.

Continuous operation of the reactor requires a valve or gate for adding fresh charge materials at regular intervals and a dump valve on the bottom of the reactor for removing unreactive waste materials periodically. The necessary pipe conduits are provided for delivering the gaseous reactants at the bottom of the shaft and for leading off the waste gases and product vapor at the top of the shaft.

Product Recovery

The hot product vapor is normally led through a crossover duct (brick-lined steel) between the reactor and the cooler. The cooler is a brick-lined box which provides a means of partially cooling the vapor by heat radiation to air prior to entering the condensers. The exit temperature of the vapor from the reactor is about 870° C and from the cooler, about 650° C.

Commercially used condensers vary from a simple air-cooled sheet steel chamber from which the product is periodically removed by hammering, to a pair of steel pipes connected in parallel, each containing a revolving scraper which continuously removes the product.

With an integrated system, the gas from the condensers would be cleaned and recycled to the reactor.

Product Purification

The chief impurities found in $AlCl_3$ made from aluminous ores are small amounts of $FeCl_3$, $TiCl_4$, $SiCl_4$, Al_2O_3, SiO_2, and Fe_2O_3. The nonvolatile solids will, in most cases, be negligible; however, resubliming would remove them, if necessary. Both $TiCl_4$ and $SiCl_4$ can be separated from the product stream by maintaining the condenser above their boiling points ($TiCl_4$, 136.4° C; $SiCl_4$, 57.6° C) and below the sublimation point of $AlCl_3$ (177.8° C). It is more difficult to separate $FeCl_3$ from $AlCl_3$ for, although $AlCl_3$ sublimes below the boiling point of $FeCl_3$ (319° C), $FeCl_3$ is volatile enough at the

sublimation temperature of $AlCl_3$ that appreciable amounts of $FeCl_3$ sublime with $AlCl_3$ (4).

Many methods have been proposed for removing $FeCl_3$ from $AlCl_3$. Some of the most feasible are listed.

1. According to the Weaver patent (52) the product vapor was passed through a bath of molten aluminum which reduced the $FeCl_3$ to iron, liberating more $AlCl_3$:

$$FeCl_3 + Al \xrightarrow[\Delta]{} Fe + AlCl_3. \tag{4}$$

This method of ferric chloride removal appears to be the most patented and most used.

2. In the Johnson patent (24) the product vapor was passed through molten lead heated to 400° C. $FeCl_3$ was reduced to $FeCl_2$ and $PbCl_2$:

$$2\ FeCl_3 + Pb \xrightarrow[400°\ C]{} 2\ FeCl_2 + PbCl_2. \tag{5}$$

The iron and lead chlorides formed a dross on the surface of the lead and could be skimmed off. It was claimed that CO_2 present in the product vapor would form oxides with iron or aluminum, if used for purification, but not with molten lead.

3. Two Castner patents (9-10) utilized molten salt baths to remove iron from the $AlCl_3$ product. In one, iron was removed by electrolyzing the product in a molten salt bath. In the other, the product vapor was passed through a bath containing aluminum dust and the iron formed from $FeCl_3$ reduction settled out.

4. In an Arnold patent (4) sufficient pressure was applied (1.5 to 2.5 atm) to the crude product in a heated container to permit melting the $AlCl_3$ and obtaining a vapor-liquid equilibrium. Thus, it was possible to prevent sublimation of either $AlCl_3$ or $FeCl_3$, distill off $AlCl_3$, and leave $FeCl_3$ in the still.

5. Krchma (28) patented the separation of $AlCl_3$ from anhydrous mixtures of $AlCl_3$ and $FeCl_3$ by solvent extraction with $TiCl_4$. The solubility of $AlCl_3$ in $TiCl_4$ is approximately 283 grams per liter at 137° C and 17 grams per liter at 25° C, whereas the solubility of $FeCl_3$ in both hot and cold $TiCl_4$ is only 0.5 gram per liter. In an example given, recovery of $AlCl_3$ containing less than 0.2 percent $FeCl_3$ was 94 percent.

6. An I.G. Farbenindustrie patent (19) proposed purifying anhydrous $AlCl_3$ containing iron compounds by converting the $AlCl_3$ into a liquid compound with phosgene, separating undissolved $FeCl_3$, and recovering the $AlCl_3$ by evaporating the phosgene.

Of these methods, the simplest would be to pass the product vapor through molten scrap aluminum. To determine the most economical method would require further investigation.

Since the amount of $FeCl_3$ obtained in the product is dependent on the amount of iron contained in the feed material, low-iron aluminous ores should be preferable as feed stock. Large-scale production of $AlCl_3$ would require the development of methods for recovering and utilizing the valuable byproducts produced in the process.

Of the byproduct metallic chlorides normally obtained, $TiCl_4$ would be the least troublesome because it is easily separated from the product and may be used for either the production of titanium metal or the preparation of pigment-grade TiO_2.

Silicon tetrachloride has use as a chemical intermediate in making silicones, metal silicides, silanes, silicon organic compounds, and silicon ammoniates. It also has use in electronics for the preparation of transistor-grade, high-purity silicon metal, in the glass industry, in the manufacture of high-purity fused-silica, and in the petroleum industry for preparing oilfield drilling muds.

Byproduct $FeCl_3$, due to its low value and the larger amounts obtained, is more of a problem. Madigan (30) oxidized byproduct $FeCl_3$ to Fe_2O_3 and chlorine at elevated temperature as shown in the equation

$$2\ FeCl_3 + 3/2\ O_2 \xrightarrow{700^\circ - 750^\circ\ C} Fe_2O_3 + 3\ Cl_2. \qquad (6)$$

The Fe_2O_3 product could be reduced to iron powder or sold as a high-grade Fe_2O_3.

Peace River Mining and Smelting, Ltd. (11), has developed a process which converts a ferrous chloride crystal made from scrap metal to iron powder and HCl. The iron powder has found a ready market with powder metal fabricators who make it into auto parts such as gears, cams, connecting rods, and pump and transmission parts.

Suppression of $SiCl_4$

Since silica in the presence of a carbon reductant will react readily with chlorine at 800° C, it is to be expected that a significant portion of any silica present in aluminous ores will be converted to $SiCl_4$ and distill off with the $AlCl_3$.

A means of suppressing the formation of $SiCl_4$ in the production of aluminum chloride from silica containing aluminous ores has been suggested by Spitzin (43) and Staib (44). Spitzin recycled $SiCl_4$ to the reactor with chlorine and reported that this suppressed the chlorination of SiO_2 without appreciable effect on the reactivity of Al_2O_3.

Karl Staib in a patent stated, "I have found that when using a mixture of about equal parts of $SiCl_4$ and chlorine and carrying out the reaction at about 750° C, there is no surplus formation of $SiCl_4$ due to reaction with the said materials, the entire chlorine content of the gas mixture being utilized for the formation of aluminum chloride." He also states that when more than 50 percent $SiCl_4$ was used, a corresponding amount of alumina was converted to $AlCl_3$, and when less than 50 percent $SiCl_4$ was used, formation of $SiCl_4$ from the solid material containing silica and alumina takes place simultaneously with the conversion of part of the latter into aluminum chloride. The means of adding $SiCl_4$ to the gas stream is stated by Staib as follows:

> The charging of the chlorine gas with the necessary amount of $SiCl_4$ may be effected in a very simple way in view of the fact that $SiCl_4$ boils at 57° C and has a high vapor tension even at ordinary temperature; therefore, by passing the chlorine gas through liquid $SiCl_4$ the chlorine becomes saturated and the amount of silicon chloride, thus taken up by the chlorine, may be easily regulated by adjusting the temperature at which the separation is carried out.

System Integration

Integration of the system for the production of aluminum by the fused-salt electrolysis of $AlCl_3$ would first require solving the problems associated with the two subsystems--preparation of $AlCl_3$ and electrolysis of $AlCl_3$.

The purified $AlCl_3$ product could be delivered directly to the electrolysis cell as a cell feed, either in vapor or solid form, whichever would be preferable. The chlorine from the cell, together with reclaimed chlorine from byproducts and the necessary makeup chlorine, would be piped directly to the $AlCl_3$ reactor.

AREAS FOR FURTHER RESEARCH

Aluminum Chloride From Clay

Anorthosite and clay represent the largest potential U.S. aluminum sources (49). Although anorthosite constitutes the bulk of these potential aluminum sources (97.5 percent), its high content of alkaline components (CaO, 11 percent; Na_2O, 5 percent) makes it unsuitable for direct chlorination to $AlCl_3$ without prior treatment.

Clays, the next largest source, have a domestic potential of 12,674 million short dry tons which contain 3,719 million short tons of alumina. At the present rate of U.S. alumina consumption (6.4 million tons in 1966) clay reserves could supply domestic aluminum needs for over 500 years.

Fire clay and kaolin represent 65.5 and 26 percent, respectively, of the total potential clay sources. Eleven States possess significant deposits of fire clay with 68 percent in Ohio and West Virginia. Thirteen States possess significant deposits of kaolin with 63.5 percent in Georgia, Arkansas, and Oregon.

A typical analysis of these two clays follows:

	Composition, percent				
	Al_2O_3	SiO_2	Fe	TiO_2	LOI[1]
Fire clay............	27	56	2.1	2	10
Kaolin...............	33	45	3.5	2	14

[1]Loss on ignition.

The preparation of $AlCl_3$ from fire clay and kaolin should be feasible because, with the exception of silica, only small amounts of chlorine-consuming constituents are present and methods previously described have been proposed to suppress the formation of $SiCl_4$.

Satisfactory commercial methods have been developed for the preparation of $AlCl_3$ from aluminum metal, Bayer alumina, and high-grade bauxite. Preparation of $AlCl_3$ from clays and other aluminous materials has occurred on a smaller scale where economics or convenience favored the use of locally obtained materials.

For the purpose of a cost evaluation of aluminum via the electrolysis-of-$AlCl_3$ process, no published information is available on the utilization of domestic clays for the preparation of $AlCl_3$. Sixteen literature references from foreign sources (1-2, 6, 14-18, 25, 27, 36, 40, 45-46, 50, 54) on $AlCl_3$-from-clay processes have been reported over the past 50 years covering the utilization of foreign clays. In the United States, no journal references and only four patents (23, 29, 37, 51) have been found concerning $AlCl_3$-from-clay processes during the same period.

The choice of domestic clays for the production of $AlCl_3$ would require investigations to determine the optimum apparatus design and operating parameters for the calcination and chlorination of the clays and purification of the product.

Calcination and Chlorination Research

Except for scrap aluminum and alunite, Al_2O_3 is the essential component of almost all aluminous raw materials. Although some work has been done on the chlorine reactivity of the transition forms of hydrated Al_2O_3, much work remains.

The chlorine reactivity of the various transition aluminas and the calcination conditions necessary to obtain them could be obtained by using the following procedure:

1. Prepare suitable quantities of the transition aluminas according to Tertian and Pappee (46).

2. Measure the pore surface area of each of the prepared aluminas by the BET method (7).

3. Devise a standard chlorination procedure.

4. Measure the chlorine reactivity of each transition alumina.

5. Correlate the results of the tests so that a comparison may be made between the transition aluminas as to their chlorine reactivity, surface area, and pore size.

The results of this investigation could be applied to the treatment of domestic clays to obtain their maximum chlorine reactivity. The calcination of these materials could be followed in the same fashion as for the pure transition aluminas:

1. Calcine the ore sample according to the conditions required to prepare the most reactive transition alumina.

2. Measure the pore surface area of the sample.

3. Measure the chlorine reactivity of the sample according to the standard chlorination procedure.

4. Correlate the results of these tests with the results obtained with the pure compounds.

Product Purification Research

Further information on product purification is necessary, especially in respect to the products from domestic clays. Since iron is one of the most objectionable impurities, a study of the many proposed iron purification methods listed under "Product Purification" would provide information to determine which is the most effective and the most economically feasible.

CONCLUSIONS

Satisfactory commercial methods of producing $AlCl_3$ from aluminum scrap, high-grade bauxite, and Bayer alumina have been developed in the United States and in other countries. Although the United States possesses large deposits of clays, little work has been done with them to determine their suitability for production of $AlCl_3$. The justification for research in producing $AlCl_3$ from clays lies in the fact that there are no large domestic reserves of high-grade bauxite and that most of the bauxite used for aluminum production in this country is imported. Current demand and technology limit the domestic commercial reserves essentially to bauxite. Both domestically and abroad the ultimate alumina and aluminum resource is the nonbauxitic clays, mainly of the kaolin type. Thus, any technologic advance that promises to improve upon the present technology of winning aluminum from clay deserves a large measure of attention.

Fundamental data for process improvements in the calcination and chlorination of aluminous raw materials and for the purification of the resulting $AlCl_3$ product, also should be gathered.

REFERENCES[3]

1. Adadurov, I. E. (Apparatus for the Production of Anhydrous Aluminum Chloride From the Clays of Donets Valley.) J. Chem. Ind. (U.S.S.R.), No. 6, 1929, pp. 1527-1530.

2. _____. (Manufacture of Aluminum Chloride from Clays.) J. Chem. Ind. (U.S.S.R.), No. 5, 1928, pp. 1288-1292.

3. Ahiya, S. P., S. P. Garg, R. T. Thampy, and N. R. Kuloor. Chloride of Aluminum, Iron, or Titanium. Indian Pat. 64,238, Oct. 10, 1959.

4. Arnold, P. M. Purifying Anhydrous Aluminum Chloride. U.S. Pat. 2,387,228, Oct. 23, 1945.

5. Atherhold, G. M. Aluminum Chloride. U.S. Pat. 2,048,987, July 28, 1936.

6. Brode, J., and C. Wurster. Chlorides. German Pat. 524,712, Mar. 24, 1926.

7. Brunauer, S. P., P. H. Emmett, and E. Teller. Adsorption of Gases in Multimolecular Layers. J. Am. Chem. Soc., v. 60, No. 2, 1938, pp. 309-319.

8. Buntin, A. P., Ya. I. Ivashentsev, and N. M. Trushkin. (Treatment of Nepheline With HCl and CCl_4 Vapor.) Tr. Tomskogo Gos. Univ., Ser. Khim. (U.S.S.R.), v. 154, 1962, pp. 52-55.

9. Castner, H. Y. Aluminum Chloride Purification. U.S. Pat. 422,500, Mar. 4, 1890.

10. _____. Purifying Aluminum Chlorides. U.S. Pat. 409,668, Aug. 27, 1889.

11. Chemical and Engineering News. Chemical Process Could Bypass Conventional Steelmaking Steps. V. 46, No. 10, Mar. 4, 1968, pp. 16-17.

12. Culberson, O. L., and W. A. Pardee. Aluminum Chloride. U.S. Pat. 2,832,668, Apr. 29, 1958.

13. Curcaneanu, D., C. Toderanu, A. Teodoru, and V. Anastasiu. (Recovery and Purification of Silicon Tetrachloride From Waste Gases During the Manufacture of Aluminum Chloride.) Stud. Cercet. Chim. 14 (Rumania), No. 19, 1966, pp. 663-670.

14. Dutt, E. E., and P. C. Dutt. Aluminum Chloride; Sodium Aluminum Chloride. British Pat. 123,243, May 10, 1918.

[3]Titles enclosed in parentheses are translations from the language in which the item was originally published.

15. Electronic Reduction Corp. Aluminum. British Pat. 650,943, Mar. 7, 1951.

16. Farbenindustrie, A.-G., I. G. Metallic Chlorides. British Pat. 281,491, Jan. 7, 1927.

17. _____. Metallic Chlorides. French Pat. 645,335, Dec. 7, 1927.

18. _____. Aluminum Chloride. British Pat. 305,578, Feb. 7, 1928.

19. _____. Aluminum Chloride Purification. British Pat. 347,510, May 26, 1930.

20. Groshev, T. L., B. G. Rabovskii, and Sh. S. Shchegol. (Chlorination of the Oxides of the Residue From Anhydrous Aluminum Chloride Production Shaft Furnace Suspended in Molten Chlorides.) Tr. po Khim. i Khim. Technol. (U.S.S.R.), No. 3, 1960, pp. 344- 351.

21. Gulf Research and Development Company. Impregnating Ore With Liquid Asphalt Which Is Subsequently Carbonized. British Pat. 807,884, Jan. 21, 1959.

22. Hille, J., and W. Dürrwächter. Herstellung von wasserfreiem Aluminiumchlorid aus γ-Tonerde in der Wirkslschicht (Manufacturing of Anhydrous Aluminum Chloride From γ-Alumina in a Fluidized Bed.) Angew. Chem., (Germany), v. 72, No. 22, 1960, pp. 850-855.

23. Jenness, Leslie G. Aluminum Chloride, etc. From Clay. U.S. Pat. 1,858,272, May 17, 1932.

24. Johnson, J. Y. Improvements in the Manufacture and Production of Aluminum Chloride Free From Iron. British Pat. 317,259, Oct. 24, 1928.

25. Khozin, A. P. Aluminum Chloride. Soviet Pat. 31,426, Oct. 31, 1933.

26. Kirk-Othmer. Encyclopedia of Chemical Technology. Interscience Publishers, New York, 2d ed., 1963, v. 2, pp. 48-50.

27. Kaczorowski, A. (Preparation of Anhydrous Aluminum Chloride From Polish Clays.) Przemysl Chem. (Poland), v. 20, 1936, pp. 221-228.

28. Krchma, I. J., and H. H. Schauman. Separation of Aluminum Chloride and Ferric Chloride. U.S. Pat. 2,502,327, Mar. 28, 1950.

29. Krucoff, Darwin. Aluminum Chloride. U.S. Pat. 2,238,421, Apr. 15, 1941.

30. Madigan, D. C., A. W. Nordin, I. B. Ketteridge, and R. E. Wilmshurst. Removal of Iron from Ores. Australian Pat. 242,474, Jan. 9, 1963.

31. McAfee, A. M. Aluminum Chloride. U.S. Pat. 1,867,672, July 19, 1932.

32. _____. Aluminum Chloride. U.S. Pat. 1,833,430, Nov. 24, 1931.

33. _____. Aluminum Chloride. U.S. Pat. 1,814,397, July 14, 1931.

34. _____. The Manufacture of Commercial Anhydrous Aluminum Chloride. Ind. and Eng. Chem., v. 21, No. 7, 1929, pp. 670-673.

35. McAfee, A. M., and G. I. Roberts. Aluminum Chloride. U.S. Pat. 1,690,990, Nov. 6, 1928.

36. Orenshtein, E. I. (Mechanism of the Drying and Roasting of Kaolin Briquets in Aluminum Chloride Production.) Khim. Prom. (U.S.S.R.), v. 43, No. 8, 1967, pp. 592-595.

37. Peacock, S. Aluminum Chloride and Sodium Silicate. U.S. Pat. 1,507,709, Sept. 9, 1924.

38. Ralston, O. C. Anhydrous Aluminum Chloride. BuMines Tech. Paper 321, 1923, 38 pp.

39. Rao, C. S. Fluidized-Bed Techniques Using Chlorine in Metallurgical Processes. Chem. Age (India), v. 17, No. 7, 1966, pp. 545-547.

40. Seferovich, Ya. E. (The Preparation of Anhydrous Aluminum Chloride by Chlorination of Kaolin in the Presence of a Catalyst.) J. Chem. Ind. (U.S.S.R.), No. 10, 1934, pp. 62-64.

41. Singleton, E. L., D. E. Kirby, and T. A. Sullivan. Electrowinning Aluminum From Aluminum Chloride. BuMines Rept. of Inv. 7212, 1968, 15 pp.

42. Spitzin, V. I., and O. M. Gwosdewa. Die Gewinnurg von wasserfreiem Aluminiumchlorid aus natürlichen aluminiumhaltigen Rohstoffen (Obtaining Anhydrous Aluminum Chloride From Natural Aluminum-Containing Raw Materials.) Z. Anorg. Allgem. Chem. (Germany), v. 196, 1931, pp. 289-311.

43. Spitzin, V. I. Das Chlorieren von Oxyden und ihren Gemischen mit Kohlenstoff. (Chlorination of Oxides; Alone and in Presence of Carbon.) Z. Anorg. Allgem. Chem. (Germany), v. 189, 1930, pp. 337-366.

44. Staib, Karl. Process for Producing Anhydrous Aluminum Chloride. U.S. Pat. 1,866,731, July 12, 1932.

45. Terekhov, M. I. Aluminum Chloride. Soviet Pat. 47,294, June 30, 1936.

46. Tertian, R., and D. Pappee. (Thermal and Hydrothermal Transformations of Alumina.) J. Chim. Phys. (U.S.S.R.), v. 55, 1958, pp. 341-353.

47. Thomas, C. A., M. B. Moshier, H. E. Morris, and R. W. Moshier. Anhydrous Aluminum Chloride in Organic Chemistry. ACS Monograph Series 87, Reinhold Publishing Corp., New York, 1941, 972 pp.

48. Treadwell, W. D., and L. Terebesi. The Chlorination of Aluminum Oxide by Chlorine and Carbon Monoxide. Helv. Chim. Acta (Switzerland), v. 15, 1932, pp. 1353-1362.

49. U.S. Bureau of Mines. Potential Sources of Aluminum. Inf. Circ. 8335, 1967, 148 pp.

50. Voronin, N. N., and I. S. Galinker. (The Preparation of Anhydrous Aluminum Chloride From Tschassow-Jar Clay.) J. Chem. Ind. (U.S.S.R.) No. 7, 1930, pp. 143-149.

51. Weaver, V. M. Process of Winning Metals. U.S. Pat. 1,238,604, Aug. 28, 1917.

52. _____. Process of Purification. U.S. Pat. 1,269,236, July 11, 1918.

53. Wurster, C. (Commercial Production of Anhydrous Aluminum Chloride.) Z. angew. Chem. (Germany), v. 43, 1930, pp. 877-880.

54. Yamamoto, K., H. Ishikawa, and K. Machida. (The Preparation of Anhydrous Aluminum Chloride From the Spent Liquor of Activated Clay.) J. Soc. Chem. Ind. (Japan), v. 39, 1936, supplementary binding, pp. 314-315.

IC bureau of mines information circular 8413

RADIATION-VENTILATION RELATIONSHIPS IN SIX UNDERGROUND URANIUM MINES

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

1969

RADIATION-VENTILATION RELATIONSHIPS IN SIX UNDERGROUND URANIUM MINES

By R. L. Rock

information circular 8413

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

Rock, Robert L

Radiation-ventilation relationships in six underground uranium mines. [Washington] U.S. Dept. of the Interior, Bureau of Mines [1969]

17 p. illus., tables. (U.S. Bureau of Mines. Information Circular 8413)

Includes bibliography.

1. Uranium mines and mining. 2. Mine ventilation. I. Title. (Series)

TN23.U71 no. 8413 622.06173

U.S. Dept. of the Int. Library

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price 30 cents

CONTENTS

ILLUSTRATIONS

TABLES

RADIATION-VENTILATION RELATIONSHIPS IN SIX UNDERGROUND URANIUM MINES

by

R. L. Rock[1]

ABSTRACT

The Bureau of Mines conducted radiation-ventilation studies in six large underground uranium mines to investigate the extent of radon-daughter exposure experienced by the miners and to analyze the ventilation systems to see what changes were required to achieve recommended radiation standards. The studies entailed tracing and measuring the mines' ventilating air, quantitatively and qualitatively, from its entrance into the mines, through production areas, and back to the surface.

Pressures consumed in creating airflow through mine circuits were determined by altimeter surveys. Air quantities were measured with anemometers or by chemical smoke cloud methods. Air quantities delivered through tubing were determined using U-tube water gages or magnahelic gages to measure velocity pressures.

Radon-daughters were filtered from mine air to measure alpha activity; activity levels were converted to "working levels," the established unit for reporting miner exposure. Attention was given to locating unnecessary contamination influx sources and recirculating air.

The radiation-ventilation surveys showed that where basic principles of good ventilation were not followed, high alpha radiation levels invariably resulted. Some mines required more primary air for controlling radiation levels throughout active areas, but more efficient use of available air was generally possible. Premature contamination of intake air was prevalent where development openings intersected ore or passed by worked-out stopes. Several auxiliary systems were inefficient in secondary distribution, recirculating air already too highly contaminated for ventilation. Many of these common problems can be traced to the lack of mine planning with radiation control in mind.

[1]Mining engineer, Health and Safety District E, Bureau of Mines, Denver, Colo.

INTRODUCTION

The Bureau of Mines' concern over radiation health hazards in uranium mines is inherent in its responsibility to promote safe health environments in the mining industry. In the years following 1950, as uranium mining grew into a sizable industry, the U.S. Public Health Service warned of a potential health hazard associated with the mining of radioactive ores (5).[2]

The hazard is believed to be from inhalation of the short-lived, airborne, alpha emitting, direct-nuclide descendants of radon gas. These nuclides, commonly called radon-daughters, attach themselves to respirable dust, or other available condensation nuclei, and are breathed into the respiratory system where a portion of them are retained. Their potential alpha energy is released in a relatively short time as they decay to longer lived nuclides. Although alpha particles have little penetrating power, they are highly ionizing.

Studies by the U.S. Public Health Service in cooperation with the U.S. Atomic Energy Commission and State agencies disclose that underground uranium miners are subject to the incidence of lung cancer to a substantially greater degree than the general population. The excess incidence apparently is related to the uranium miner's occupational environment, and is believed to be induced by the radioactive decay of radon-daughters in the respiratory system.

Where serious doubts concerning the health hazard still persist, they pertain to the radiation levels that can be tolerated day after day without noticeably increasing the hazard. During 1967, extensive hearings were held before the Congressional Joint Committee on Atomic Energy (7) to settle contoversy over the setting of a tolerable radiation exposure standard for radon-daughters in underground mines. Also, the Federal Radiation Council (4) recognized that, while mining conditions had improved greatly over those prevailing 10 years previously, more improvement was needed to provide proper control of exposure to radon-daughters. The council then adopted an interim standard of one working level (1 WL) in order to affect immediate improvements; they further recommended that actual exposure should be kept as far below this value as practicable.[3]

State and Federal agencies have been surveying airborne alpha-particle-emitting contaminant (radon-daughter) levels in the Nation's underground uranium mines for the last 10 years. These surveys, plus industry surveys, allow a fairly accurate appraisal of the general radon-daughter levels existing in the mines during this period. Medical data and exposure levels are continually being correlated by the Public Health Service in an attempt to further define acceptable levels of exposure. The Bureau has, and continues to contribute, much of the exposure level data used in the correlative efforts.

---

[2]Underlined numbers in parentheses refer to items in the list of references at the end of this report.

[3]One working level is 1.3×10^5 million electron volts of potential alpha energy per liter of air from the daughters Ra, RaB, and RaC.

The Bureau initiated radiation surveys in all the Nation's underground uranium mines in Spring 1967, under the authority of the Federal Metal and Nonmetallic Mine Safety Act (80 Stat. 772), delegated by the Secretary of the Interior. Although the number of active mines changed because of mine closures and reopenings, 180 plus or minus 10 percent was the determined number of mines operating at any one time during the survey period ending May 10, 1968. The mines employed about 2,100 underground workers in New Mexico, Wyoming, Colorado, Utah, Arizona, California, and South Dakota. All of the mines were surveyed for radon-daughter levels; resurveys have been made as the continuity of the operations allowed. Appropriate summaries of exposure level data obtained from these surveys are continually being prepared and distributed (3). The Bureau's quarterly Mineral Industry Survey's health and safety summary is one way the information is disseminated. These surveys are very important in indicating existing radiation levels and progress toward improvement. However, they are not detailed enough to either provide answers as to why high radiation levels persist in some instances or to indicate how improvements can best be implemented.

To provide information for answering these important questions, six of the larger uranium mines, having widely different mining methods, were selected for detailed radiation-ventilation studies. Ventilation patterns are similar at some of the operations, but there is enough diversity to be representative of general practices in the industry. About 300 underground workers, 15 percent of the total U.S. underground uranium work force, are represented by the six operations studied.

This paper summarizes radiation levels found at the six operations studied, basic radiation-ventilation relationships revealed, and major causes of high exposure levels.

ACKNOWLEDGMENTS

Mining company personnel facilitated sampling and obtaining many of the data upon which this paper is based. Their regard for the problem was demonstrated by their cooperation in conducting these detailed studies. Because information presented is believed to be representative of general industry problems and is not intended as criticism of individual companies or mines, cooperating companies are not identified.

MINING PRACTICES

All but one of the ore bodies studied are relatively flat-lying and occur in sandstone. The other deposit occurs in a Precambrian gneiss and fits the general description of a steeply dipping vein deposit, although multiple intersecting veins and ore shoots are involved. Most of the flat-lying deposits occur in more than one stratigraphic horizon and are oriented along bedding planes.

The smaller sandstone ore deposits, consisting of a few hundred to a few thousand tons each, occur as a series of intermittent lenses and pods. These smaller deposits are difficult to define in advance of mining; therefore, planned, systematic extraction is seldom practiced. The usual method is to explore, develop, and extract at the same time. Sometimes single track

entries are driven below the ore, but more often entries are located in the ore.

In the larger deposits, systematic extraction is easier to attain. Most often, sublevel haulageways are driven, and ore on the levels above is mined by room and pillar methods. Cut and fill and square set mining is used in some of the thicker deposits. Caving is successfully applied in large, thick pillar sections by driving raises from below and ring drilling the pillars. Caving is initiated by blasting the drill holes; the raises serve as drawholes for removing the ore.

Shrinkage and open stoping methods are used to mine the single vein deposit studied. Deposits are opened by adits or shafts, depending upon the relationship between the ore and topography. Boreholes are widely used to supplement ventilation and to provide escape openings.

Both track and trackless haulage and loading equipment are used. Slushers are used in scram drifts and with slusher-ramp loading arrangements. Most equipment is electrically or air powered, but a few diesel-powered front-end loaders and ore carriers are employed. Ore and waste are drilled using pneumatic jack-leg drills. The mines studied are well mechanized, and little hand mucking or hand tramming is utilized. Electrical power was available at all the mines.

STUDY PROCEDURES

General

Each detailed study required tracing and measuring the ventilating air both quantitatively and qualitatively (for alpha radiation from airborne particulates) from the point where fresh air entered the mine to ventilation distribution points in production areas and finally to where return air was exhausted at the surface.

Two to four men participated in each study. Average time requirements to secure field data for each study were about 30 man-days.

Company mine maps were first analyzed, then brought up to date to show ventilation patterns and controlling features governing the ventilating system. Active and inactive areas were located, and a line diagram depicting ventilation circuits was constructed for use as a working guide.

Ventilation Measurements

Airflow quantity measurements were made using the full-traverse anemometer method wherever possible. The chemical smoke-cloud measurement method was used where air velocities were below anemometer range. Auxiliary vent-tubing quantities were determined with the aid of a pitot tube and water gage. Velocity pressures were corrected for density to allow better quantity calculations of the air passing through tubing. All quantities measured were recorded directly on the working map, and a preliminary quantity balance was

made as work was progressed, making it possible to immediately identify where leakage and recirculation were occurring. Radiation levels from radon-daughters were measured during the quantity survey to assure that alpha radiation levels measured reflected the conditions of air quantities being delivered. Radiation levels were also recorded on the working map where they could easily be examined. To verify data, repeat samples and check air measurements were made.

Finally, absolute system pressures were measured using two 4,000- to 11,000-foot-range precision altimeters (6). One altimeter was used as a base to record normal pressure changes in the surface atmosphere. The other instrument was used as the roving altimeter to measure static pressures between

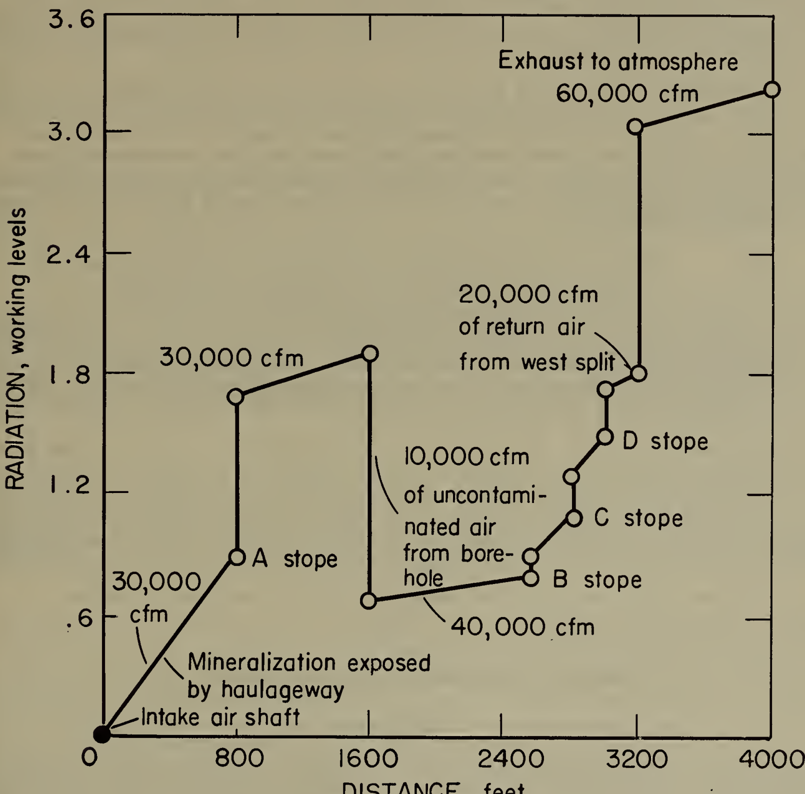


FIGURE 1. - Example of Radiation Profile Showing Radiation Buildup Due to Contaminant Inflow.

selected stations in the ventilation system. Magnahelic-gage readings and U-tube water-gage readings were taken to augment altimeter measurements. By correcting roving altimeter readings for elevation differences, surface barometer changes, and velocity pressure differences, the pressure consumed in causing flow between stations was indicated.

Radiation Measurements

Radon-daughters were filtered from the mine air, and the alpha activity on the filters was measured using the standard field method (1). Total alpha activity on the filters was converted from disintegrations per minute (dpm) to "working levels," the established unit for reporting potential alpha radiation from radon-daughters, by dividing the dpm count by liters of air filtered, and multiplying this by the appropriate elapsed time factor. Chemical smoke clouds were used liberally to assure that air currents sampled were truly representative of the portion of the mine atmosphere desired for testing. This insured that invisible air interfaces did not mask the relationships being sought.

Special attention was given to locating contamination intake sources. A radiation profile map is sometimes helpful in depicting the contamination buildup that occurs while intake air circulates through the mine. Figure 1 is a generalized example of the form such a profile might take. Main areas of exposure were carefully sampled, and timestudies were obtained to allow full-shift exposure calculations for each man (2). Table 1 summarizes individual samples and full-shift exposures determined from them.

TABLE 1. - Summary of all radon-daughter samples and individual employee full-shift exposures, by mines and working levels

Mines	Working level ranges												Total	
	0-0.3		0.4-1.0		1.1-3.0		3.1-5.0		5.1-10.0		>10		Samples	Exposures
	Samples	Exposures	Samples	Exposures	Samples	Exposures	Samples	Exposures	Samples	Exposures	Samples	Exposures		
1......	14	43	10	10	7	5	2	0	0	0	0	-	33	58
2......	4	1	5	6	7	31	6	17	5	2	0	0	27	57
3......	14	36	6	7	6	4	6	4	8	10	6	3	46	64
4......	13	0	17	10	27	10	2	0	0	0	0	0	59	20
5......	3	7	2	5	1	9	5	3	8	7	3	0	22	33
6......	1	0	6	2	7	11	4	12	16	28	4	2	38	53
Total..	49	87	46	40	55	70	25	36	37	47	13	5	225	285
Percent	22	30	21	14	24	25	11	13	16	16	6	2	100	100

A detailed report was given the operator following each study in which radiation-ventilation conditions were described, and recommendations for improving radiation levels were presented.

MAJOR RADIATION-VENTILATION RELATIONSHIPS[4]

Mine 1

Mine 1 is a shaft mine ventilated by four surface fans exhausting air through metal-cased 30- to 36-inch boreholes 600 to 700 feet deep, moving 88,000 cubic feet

[4]Table 1 should be referred to for the number of underground employees and radiation exposure levels, at the respective operations described.

per minute (cfm) of air into the shaft. About 3,000 cfm of additional air entered the mine through another cased borehole open to the surface, but not provided with a fan. Of the total intake air, only about 38,000 cfm was used to ventilate the single major multilevel production section. Most of the remaining intake air was lost through stoppings and ore passes connecting old stoping areas with the main haulageway and intake airway.

Intake air arrived at the primary production area relatively uncontaminated because the intake airway was in barren ground below the ore, and abandoned connecting stoping areas were kept at negative pressure with respect to the airway.

Air was distributed to the various mining levels above the haulage level through manways and ore passes. Air movement on and between the levels was not well controlled, and recirculation was evident. Only some of the small auxiliary fans, used with vent-tubing to spot-ventilate individual working places, were effective; others were not, chiefly because of problems with recirculation at the fan inlets and poor tubing maintenance.

Some of the room and pillar stoping levels were quite large, and the air, following a random path of least resistance, had a tendency to channel through them, leaving fringe areas poorly ventilated. Such fringe areas then became reservoirs for contamination buildup and complicated the general control problem.

More air and better distribution efficiency were needed in the major production area. Without appreciably improving distribution efficiency, the air quantity would have to be nearly doubled to limit the radiation in all work locations to 1 WL. If, however, recirculation was prevented, and more uniform flow was obtained through stoping areas, the available air should have been nearly enough to control radiation levels in existing stoping volumes.

Pressure requirements and attendant power costs for ventilating through small-diameter boreholes are always high. In this case, about 80 percent of the system resistance was in the primary borehole. Also, the main fan was operating at an inefficient location on the fan characteristic curve, and by adjusting the fan blades, it was possible to lower power costs almost 50 percent with only a 3-percent loss in air quantity.

Mine 2

Ventilation was induced by two tandem-connected surface fans blowing air underground through a 1,430-foot, 36-inch-diameter cased borehole. A booster fan on the lower stoping level added pressure to the primary flow which was coursed through raises and draw holes into the upper mining levels. All the return air was collected on the track level and returned to the surface through the hoisting shaft. Of the 59,000 cfm of air entering the vent shaft, only 36,000 cfm was left for ventilating production areas after leakage and after splits were taken off for ventilating the shop, lunchroom, and transformer station. The booster fan was handling 58,000 cfm of air, but 22,000 cfm of this air was recirculated from the track haulage level and adjacent

tailing-sand-filled stopes. This recirculation in the primary circuit, besides increasing the hazard from smoke or fire originating underground, allowed contamination inflow to raise the radon-daughter concentration in the immediate main intake air to 0.4 WL.

Further contamination of part of this intake air occurred when it passed mill tailing-filled stopes on its way to the production area. This air was already contaminated to 3.4 WL at the intake to the stope fan, and miners were exposed to about 5.8 WL in the stopes.

Auxiliary fans and tubing were used to ventilate individual working places. At least three of these units were recirculating air already highly contaminated.

An estimated 15,000 cfm of additional uncontaminated primary air could be made available by eliminating unnecessary leakage between intake and return airways. The main radiation problem, however, was due to the large acceptance of contamination inflow. Fortunately, mill tailings were no longer being used for filling stopes. A planned 48-inch diameter drill hole should allow altering the ventilating system so contamination inflow from existing tailing-filled stopes will be minimized. Using the new system, tailing-filled stopes along the present sublevel intake air course will be on return air and the track haulage level will become the main intake air course. The system should also minimize series ventilation between working places. The quantity of air required to keep radiation levels in safe ranges in all the mine areas could not be determined accurately for this mine. It should be possible, however, to utilize the planned 75,000 cfm more efficiently with the proposed distribution changes.

Almost 24 inches of water gage pressure was consumed in causing the 59,000 cfm of intake air to enter the mine through the 36-inch-diameter borehole.

Mine 3

Mine 3 was ventilated with 267,000 cfm of air exhausted by six fans through five boreholes and a raise. The largest borehole was 60 inches in diameter; average ventilation shaft depth was about 700 feet. Air entered the mine through the hoisting shaft and two additional intake boreholes.

Because the mine was in the very mature stages of development, only the ventilation pattern in the major active production section will be discussed here. In this section, air entered the haulage level from the hoisting shaft and one of the intake boreholes and was then distributed up to the mining level through manways and ore passes. The main mining level was a large room and pillar area with sealed caved areas around the margins. All the workers on this level were exposed to radon-daughter concentrations well in excess of 1 WL. Although the problem was complicated by other factors, the major reason for the high levels was that sealed areas were interconnected with the exhaust shaft in such a way that they were at a positive pressure with respect to active stoping areas. Contamination inflow into the active stoping areas was

excessive to the extent that 35 WL resulted in some localities. Other contributing factors were the lack of control of intake air movement through the pillar area away from the direction of mining and a few poorly installed auxiliary air distribution systems.

Auxiliary spot ventilation systems lose much of their effectiveness if radiation levels in the general stope area are allowed to become too high. Several thousand cubic feet per minute of uncontaminated air discharged into such an area may be effective only within a few feet of the tubing discharge because of the rapid entrainment of the highly contaminated air.

Because modifications of the ventilation system could be expected to greatly reduce the quantities of air necessary to control radiation levels on the main production level, no attempt was made to project future requirements on the basis of existing conditions.

Several mine areas of excessive resistance to airflow were indicated by the pressure survey.

Mine 4

Air entered the mine through two adits, each leading to production areas, and a surface fan, installed over a 420-foot shaft, exhausted 74,000 cfm of air. Distribution through the adits was governed by the relative system resistance of each. One dead-end production area was pressure ventilated by about 4,700 cfm through a 15-inch-diameter ventilation borehole.

Single-entry track haulageways formed the intake airways either in or below the ore horizons. Doors, stoppings, and regulators were used to control air movement along active splits. Where face ventilation could not be provided in this way, auxiliary fans with vent-tubing were used.

Filtered-air samples indicated that radon-daughter levels in the active production areas off both adits averaged about twice the recommended maximum. The intake air of both major splits was contaminated as the air circulated by and through old stoping areas on its way toward current production locations. Intake air at the inlets to auxiliary fans was generally already too highly contaminated to effectively control radiation in face areas. In addition, discharge ends of tubing terminated much too far from work locations to allow available air to be effective.

It was found that the air provided through the borehole, and intended to ventilate the dead-end workings off one of the main splits, was being short-circuited so that the auxiliary fan could not pick it up. Instead, the fan was recirculating air at 2.0-4.0 WL within the mine volume surrounding the tubing. A single check curtain was installed which redirected the uncontaminated air from the borehole to the fan inlet and remedied the radiation problem in this particular locality. This was not the end of the problem, however, because the return air later mixed with the intake air to the next stoping area downwind. This is but one example of contamination problems resulting from series ventilation through the overall mine complex.

Because systematic sealing of old stoping areas along intake airways would lessen the quantity of air required to control radiation levels throughout the mine, no attempt was made to estimate the quantity required for ventilation under existing conditions.

The pressure portion of the survey did not reveal any areas of unusually high resistance to airflow, but it did indicate that existing equipment was operating near its maximum capacity. To obtain more primary flow, a higher capacity fan would be needed, or the overall system resistance would have to be significantly reduced.

Mine 5

Primary air entered the operating adit and was coursed several hundred feet underground (fig. 2), where two auxiliary fans were used to blow part of the primary air through tubing to four active mining levels below the collar of a winze. A 20-inch-diameter tubing was installed in the restricted area of the winze's manway compartment. Total primary air was 22,500 cfm; air arriving on each active mining level through the tubing was 3,100 to 4,500 cfm. Remaining primary air flowed through the hoisting compartment of the winze to the first level and out through old open stopes to the main exhaust fan adit above.

Radon-daughter samples taken on the mining levels and in the steeply dipping stopes indicated that nearly all the miners working below the collar of the winze were being exposed to alpha radiation from airborne radon-daughters in excess of 1 WL.

The prime cause for the high radiation levels was insufficient ventilating capacity. Tubing was extended well into the stopes; but air quantities discharged were only a few hundred cubic feet per minute because of the limited quantity that could be delivered through the tubing in the winze, leakage, and the large number of splits necessary on the levels. Another contributing factor to the high radiation levels was recirculation of contaminated return air from stopes on and between the levels.

The best solution to the problem appeared to be the provision of an adequate capacity exhaust fan operating through a new shaft connecting the mining levels with the surface, near their farthest extension from the winze. Air then would enter levels through the present winze and could be regulated near where the levels intersect the proposed shaft. Auxiliary fans and tubing would be needed to course air from the levels into active stopes, but tubing distances would be minimal. The present exhaust fan could still be used to maintain an upward flow of air through the stoped-out areas above the present mining levels. It was estimated that about 35,000 cfm of air, efficiently distributed between existing mining levels, should be adequate to lower alpha radiation from airborne contaminants to 1 WL.

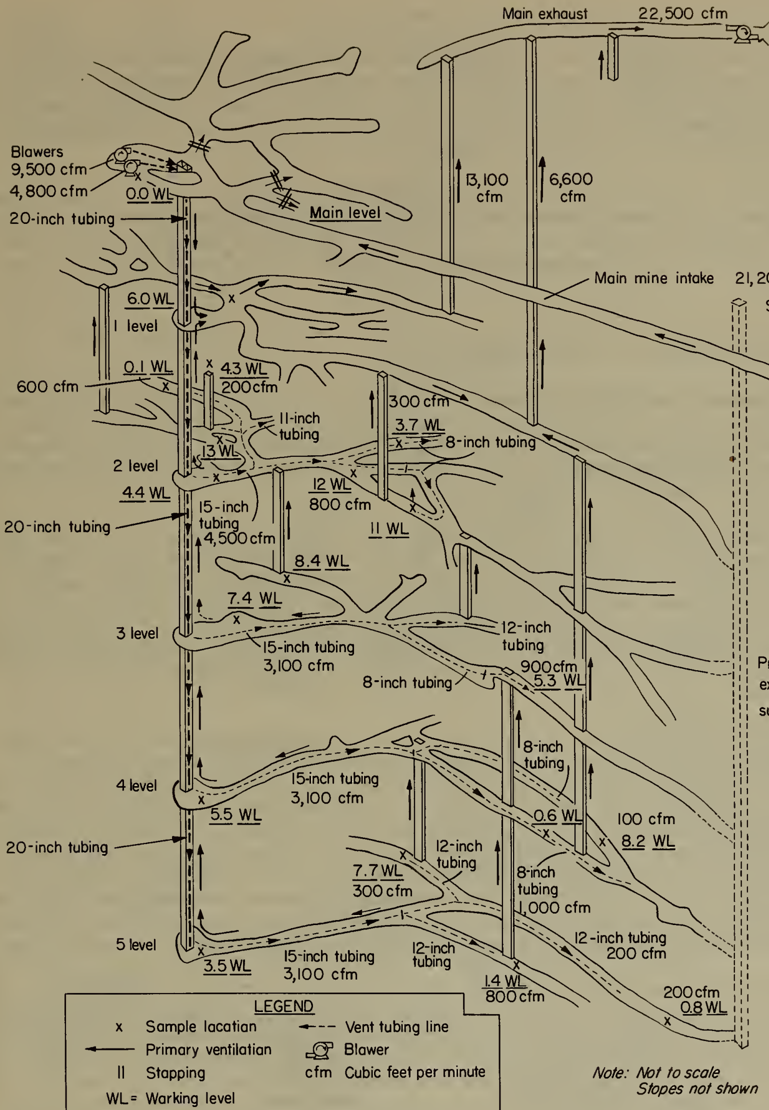


FIGURE 2. - Isometric Sketch of Radiation-Ventilation Relationships at Mine 5.

Mine 6

This mine (fig. 3) is a good example of an operation that originated as a group of small separate mines, but became interconnected. Ore deposits were relatively small and occurred as irregular lenses and pods within a flat-lying sandstone formation. A shaft and two adits were the operating openings. A third adit was used solely as an air course.

Primary ventilation was induced by four surface fans, two blowing through tubing and two blowing through drill holes, and by two underground fans operating in bulkheads. Intake air totaled 43,900 cfm. Five auxiliary fans were used underground to blow air through tubing into active areas off the primary circuits.

All but two of the underground employees were receiving more than 1 WL full-shift exposure to radon-daughters.

Management was in the process of increasing primary flow through the main production section by installing a larger primary fan underground. It was very necessary to increase primary flow in this section of the mine, because auxiliary units were handling 1-3/4 times the primary quantity of air provided. Recirculation was thus inevitable.

Contamination inflow was also a serious problem. Intake air to the section passed through a mined-out area shortly after it entered the portal of the mine and was at nearly 5 WL by the time it arrived at the first auxiliary fan inlet. Masonry seals were being constructed to alleviate this condition, but the mined-out area presented a formidable sealing problem. A number of chutes, in addition to side drifts, required sealing, and it was possible that considerable contamination inflow came from fill and spillage along the adit floor itself.

About half the total 200 horsepower being expended for ventilation was wasted, either because of direct recirculation or because inlet air was already too highly contaminated to be usable. In general, auxiliary units were poorly designed and poorly applied. Besides massive recirculation at the fan inlets, leakage from tubing joints and holes reduced the quantity of air discharged at work locations to ineffectual proportions. Often, discharge ends of tubing were too far back from faces they were intended to ventilate. One auxiliary unit was actually detrimental; it raised the radiation level in the area it served. This fan was picking up highly contaminated air from an inactive area and injecting it into an active location near a fresh air source.

No attempt was made to predict the total quantity of air necessary to control radiation levels throughout the mine. Obviously, enough uncontaminated air must be provided to allow auxiliary units to function without recirculation. The ability to isolate contamination sources from intake air appears to be the factor governing whether the new main fan will achieve the desired results. Another contingency will be the ability to coordinate flow to and from active sections in such a way that return air from one section does not foul the intake air of the next. The latter would be simpler to achieve if

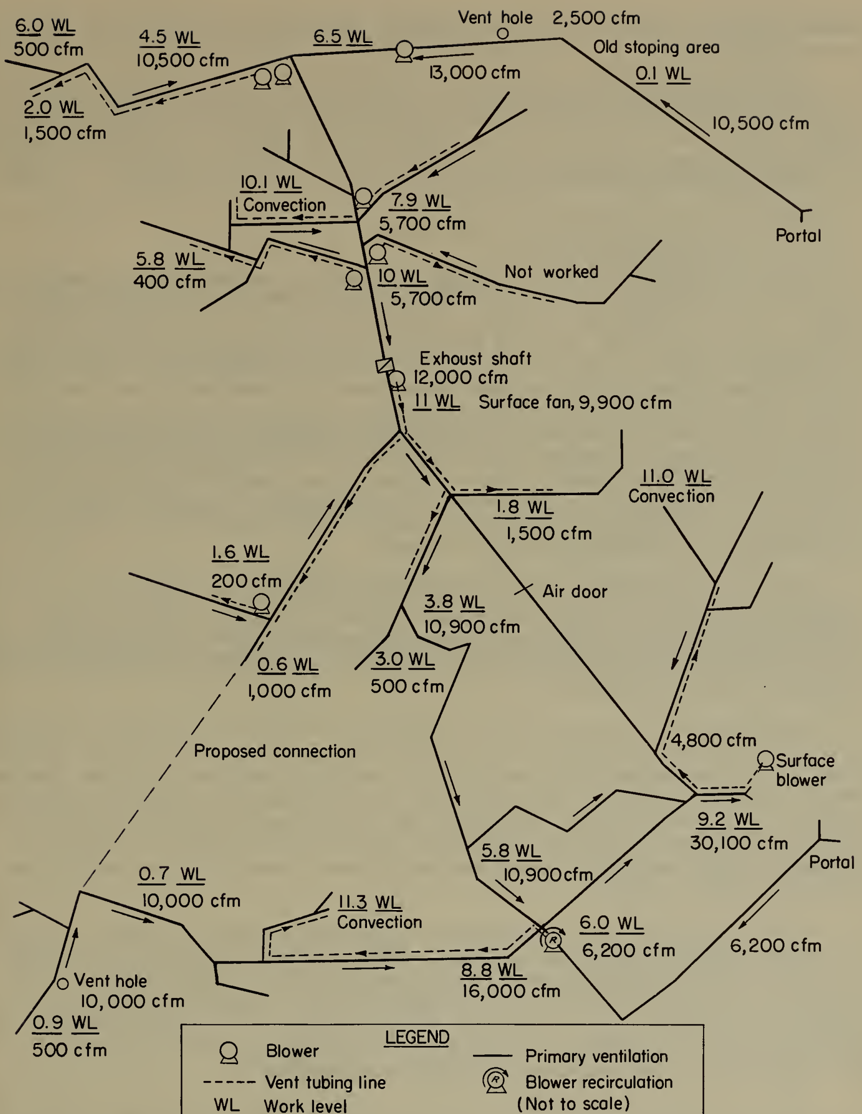


FIGURE 3. - Plan Line Diagram Showing Radiation-Ventilation Relationships at Mine 6.

production areas could be more consolidated; then available air would not be spread so thinly.

The pressure portion of the survey revealed a fine balance between natural draft pressure and mechanically induced pressure which threatened directional control over the air in the vicinity of the shaft. Directional control must be maintained to assure that contaminated air is not periodically coursed in a deleterious manner.

CONCLUSION

Radiation hazards in the six mines studies are aggravated by a number of factors, the broadest of which is a lack of mine planning for radon-daughter control. It is recognized, however, that the mines are in the mature stages of development, and that the need for more mine planning to facilitate radiation control cannot be attributed solely to the shortsightedness of the operators. In many cases, the major development work in these mines was done prior to 1960 when there was still some disagreement among authorities as to the severity of radiation hazards and the lack of comprehensive knowledge concerning the relationship of exposure to radon-daughter atmospheres and the incidence of respiratory disease. When developing new stopes in old mines, more attention is being given to the need for mine planning to achieve radiation controls and to keep ventilation costs down. Future mines can be expected to be developed with radiation control in mind.

A major factor found, which is sometimes difficult to correct, was contamination inflow into intake air from nonproductive areas. Contamination influx was so severe in some places that sufficient intake air volumes could not be practically provided to dilute contamination enough to make the air usable for face ventilation.

Sometimes, more primary air was needed, but with few exceptions available air was not being optimally utilized. More fans and more air movement are the first control measures which come to mind, but it is apparent from the studies that, unless the added air is efficiently distributed and integrated with the overall ventilating system, results can be very disappointing and expensive. The interrelationship between ventilation patterns and radiation levels in different mining sections is such that adjustments benefiting one section may adversely affect another.

Table 2 outlines the major causes of high radon-daughter exposure in the six mines studied in order of severity. Table 3 shows a comparison of radiation levels found during the six radiation-ventilation studies and radiation resurveys made a few months later. Although repeat detailed radiation-ventilation studies would be required to allow precise correlation between fulfillment of study report recommendations and radiation level improvements, the comparison is indicative of significant improvement.

The most disturbing revelation of the studies was the frequent violations of good ventilating practices. Recirculation of air in primary and auxiliary circuits was found all too often. Leakage was a problem, especially in

auxiliary systems utilizing tubing. Discharge ends of tubing were sometimes too far from production areas to be effective, and a few fans were found turned off because of someone's discomfort. Although they demand constant attention, conditions such as these should be easy to locate and correct. Only minor changes in the present systems were required to significantly lower radiation levels in a number of instances.

TABLE 2. - Summary of major causes of high radon-daughter exposure levels

Major causes	Relative cause importance						
	At individual mines[1]						Overall[2]
	1	2	3	4	5	6	
Unnecessary acceptance of contamination inflow	2	6	6	5	1	6	26
Poorly designed auxiliary ventilation systems (recirculation or improper delivery at the face)......................................	5	4	4	4	4	4	25
Insufficient ventilation quantity (judged on the basis of efficient distribution and utilization of available air)....................	4	3	3	2	6	5	23
Series ventilation between major mining sections..................................	3	5	2	6	2	3	21
Lack of directional control over available air	6	1	5	1	5	1	19
Main operating openings in return air.........	1	2	1	3	3	2	12

[1]Cause importance at each mine is indicated by the decreasing range 6-1.
[2]Cause importance for all mines is indicated by the decreasing range 26-12.

TABLE 3. - Comparison of percentages of men in various full-shift exposure ranges during radiation-ventilation studies and radiation surveys[1]

Study and survey	Men exposed to various working level ranges, percent					
	0-0.3 WL	0.4-1.0 WL	1.1-3.0 WL	3.1-5.0 WL	5.1-10.0 WL	>10 WL
MINE 1						
Radiation-ventilation study........	74	17	9	-	-	-
Cumulative, percent................	74	91	100	-	-	-
Radiation survey...................	29	60	9	2	-	-
Cumulative, percent................	29	89	98	100	-	-
MINE 2						
Radiation-ventilation study........	2	11	54	30	3	-
Cumulative, percent................	2	13	67	97	100	-
Radiation survey...................	22	64	14	-	-	-
Cumulative, percent................	22	86	100	-	-	-
MINE 3						
Radiation-ventilation study........	56	11	6	6	16	5
Cumulative, percent................	56	67	73	79	95	100
Radiation survey...................	43	46	8	0	3	-
Cumulative, percent................	43	89	97	97	100	-
MINE 4[2]						
Radiation survey...................	0	0	0	18	82	-
Cumulative, percent................	0	0	0	18	100	-
Radiation-ventilation study........	0	42	58	-	-	-
Cumulative, percent................	0	42	100	-	-	-
MINE 5						
Radiation-ventilation study........	21	15	27	9	21	7
Cumulative, percent................	21	36	63	72	93	100
Radiation survey...................	48	32	20	-	-	-
Cumulative, percent................	48	80	100	-	-	-
MINE 6						
Radiation-ventilation study........	0	4	21	23	52	0
Cumulative, percent................	0	4	25	48	100	-
Radiation survey...................	0	4	89	0	7	0
Cumulative, percent................	0	4	93	93	100	-

[1]Slightly higher exposure levels obtained during radiation surveys are believed to represent a fluctuation within normal transient conditions.

[2]Radiation survey made prior to radiation-ventilation study.

REFERENCES

1. American Standards Association (now United States of America Standards Institute). Radiation Protection in Uranium Mines and Mills (Concentrators). American Standard N7.1, 1960, 31 pp.

2. Bates, R. C., and R. L. Rock. Estimating Daily Exposures of Underground Uranium Miners to Airborne Radon-Daughter Products. BuMines Rept. of Inv. 6106, 1962, 22 pp.

3. Bureau of Mines. Progress Reports to Federal Radiation Council Task Force on Uranium Mining, December 1967, March 1968, and May 1968 (unpublished).

4. Federal Radiation Council. Guidance for the Control of Radiation Hazards in Uranium Mining. Rept. 8 (rev.), September 1967, 60 pp.

5. Holaday, Duncan A., David E. Rushing, Richard D. Coleman, Paul F. Woolrich, Howard L. Kusnetz, and William F. Bole. Control of Radon and Daughters in Uranium Mines and Calculations on Biological Effects. U.S. Public Health Service, Public Health Pub. 494, 1957, 81 pp.

6. McElroy, G. E., and D. S. Kingery. Making Ventilation-Pressure Surveys With Altimeters. BuMines Inf. Circ. 7809, 1957, 20 pp.

7. U.S. Congress. Radiation Exposure of Uranium Miners. Hearings before the Subcommittee on Research, Development, and Radiation of the Joint Committee on Atomic Energy. 90th Cong., 1st Sess. 1967, pt. 1, 783 pp.; pt. 2, 1373 pp.

U. S. GOVERNMENT PRINTING OFFICE : 1969 O - 348-540

IC bureau of mines information circular 8414

A METHOD OF MEASURING THE COSTS AND BENEFITS OF APPLIED RESEARCH

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

1969

A METHOD OF MEASURING THE COSTS AND BENEFITS OF APPLIED RESEARCH

By John W. Sprague

* * * * * * * * * * * information circular 8414

UNITED STATES DEPARTMENT OF THE INTERIOR
Walter J. Hickel, Secretary

BUREAU OF MINES
John F. O'Leary, Director

This publication has been cataloged as follows:

Sprague, John W

A method of measuring the costs and benefits of applied research. [Washington] U.S. Dept. of the Interior, Bureau of Mines [1969]

42 p. illus., tables. (U.S. Bureau of Mines. Information Circular 8414)

Includes bibliography.

1. Cost effectiveness. 2. Research, Industrial—Methodology. I. Title. (Series)

TN23.U71 no. 8414 622.06173

U.S. Dept. of the Int. Library

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price 50cents

CONTENTS

ILLUSTRATION

TABLES

A METHOD OF MEASURING THE COSTS AND BENEFITS OF APPLIED RESEARCH

by

John W. Sprague[1]

ABSTRACT

The Bureau of Mines studied the application of the concepts and methods of cost-benefit analysis to the problem of ranking alternative applied research projects. Procedures for measuring the different classes of project costs and benefits, both private and public, are outlined, and cost-benefit calculations are presented, based on the criteria of probability of success and internal rate of return. Because of increasing concern about environmental effects, the methodology and data requirements for estimating project-related pollution costs are discussed. Also, a case study of cost-benefit analysis for a heavy metals program is presented.

CONCEPTUAL BACKGROUND

In a market system, such as that of the United States, prices and costs (which are nothing but the prices of inputs) serve as signals to firms and individuals, permitting them to make decisions on grounds of economic efficiency leading to most profitable positions. However, there are many situations for which prices do not exist or cannot be used directly. Cost-benefit analysis has been developed by economists to interpret these situations.

Cost-benefit analysis is a conceptual and empirical technique for determining which of several courses of action will be, in some sense, most profitable. In effect, it can serve the same purposes as a marketplace. Cost-benefit analysis has most often been applied in the public sector where collective goods, like national defense, or indivisible goods, like dams, are being provided. More recently, it has come to be used to evaluate alternative applied research programs. This information circular outlines an approach to cost-benefit study for applied research projects of the type undertaken by the Bureau of Mines.

---

[1]Economist, Bureau of Land Management, Washington, D.C.; formerly with Division of Mineral Economics, Bureau of Mines, Washington, D.C.

Cost-Benefit Analysis and Applied Research

The methodology used here for measuring the economic benefits of applied research programs takes the project as the basic unit of analysis, and uses the project's internal rate of return as the means for ranking and the probability-of-success factor as a means of offsetting potential "project myopia."

However, many factors, other than economic benefits, play a role in determining which of the many alternative research possibilities will be undertaken. These noneconomic factors develop the basic parameters within which cost-benefit analysis is used.[2] Some of these factors are (1) the mission and role of the organization, (2) the existing and potential capabilities of scientific and technical personnel, (3) the necessity for maintaining a core program, and (4) the establishment of a balanced program.

In any attempt to develop a coherent and comprehensive research program the overall process of evaluating resources and objectives must be broadly conceived. However, the constraints of a limited budget inevitably necessitate compromises. Cost-benefit analysis can aid in choosing both among various desirable objectives and among various possible routes to those objectives by comparing alternatives in terms of a common denominator.

The methodology presented in this paper is designed to operate within a framework of appropriate criteria provided by the decisionmaker and to respond to changes in such basic parameters as time horizons, input limitations, technological constraints, and assumptions as to reasonable investment alternatives. Although cost-benefit analysis cannot establish these basic parameters, it can measure the likely benefits or costs of projects designed to operate within them. Thus, cost-benefit analysis functions as a tool to assist management in its attempt to optimize the use of available funds.

The cost-benefit methodology developed in this paper is intended for applied research, which normally has a specific goal such as the more efficient utilization of a scarce resource, increased utilization of an abundant resource, or reductions in environmental pollution. The potential benefits of an applied research project can be predicted and evaluated, both because of a reasonable degree of certainty as to its extent and area of impact, and because of the relatively short time span between performance of the research and implementation of its results.

---

[2] For a more detailed treatment in this area see Vogely (19, pp. 28-38). (Underlined numbers in parentheses refer to items in the Bibliography preceding the appendixes.)

Analysis of pure research, on the other hand, usually involves the consideration of a much longer time span with far less certainty as to the results' area and degree of impact. Theoretically, the techniques of cost-benefit measurement are the same for all research, but discussion will be confined to applied research projects owing to the greater degree of uncertainty involved in the analysis of pure research.

Appendixes A and B are included to provide guidelines and examples for measuring a project's costs and benefits.

Appendix A deals with pollution costs and benefits; it provides a methodology of measurement and indicates necessary data inputs. Because of the flexible nature of this type of analysis, the guidelines provided are of a very general nature and may be varied as the specifics of each project analysis require.

Appendix B is an actual case study performed by the Bureau of Mines in 1967 and shows the methodology and data inputs utilized in estimating a project's direct benefits. No attempt was made to quantify external costs in this appendix.

Therefore, appendixes A and B should be viewed as companion documents providing guidelines on overall cost and benefit quantification, appendix A on a project's external effects and appendix B on a project's direct effects.

Types of Project Costs and Benefits

At least in principle, cost-benefit analysis can take into account all of the costs entailed and all of the benefits created by each alternative. Applied research projects of the type undertaken by the Bureau of Mines entail the following classes of costs and benefits:

1. Direct--increases in the production of goods and services. Measured in dollar terms.

2. External (Spillover)--

   A. Pecuniary--offsetting effects. Not included in calculations.

   B. Technological--

      (1) The adaptation of research results by industries other than the one to which project research is primarily oriented. Represents increases in the production of goods and services by these industries. Measured in dollar terms.

      (2) Changes in existing levels of air, water, and land pollution. Measured by potential effects in order of magnitude terms, and by dollar and intangible terms where applicable.

(3) Changes in existing health and safety conditions. Measured by a combination of dollar and intangible terms.

3. Secondary--

A. National--offsetting effects. Not included in calculations.

B. Regional--measured in dollar terms to the degree practicable.

4. Intangible--described in qualitative terms, or in "at-least" values.

5. Prescribed goals--defined by policymaker; such considerations as balance-of-payments.

More detailed treatment of each of these categories is presented in later sections.

In determining project benefits, the following data are computed:

1. Direct net benefits or costs.

2. Net benefits or costs from technological spillovers under above category B-1.

3. The measurable portion of costs and benefits under above categories B-2 and B-3.

4. Any prescribed benefits or costs which are quantifiable. Other project aspects should be subjected to a separate analysis in whatever units of measurement they may be quantifiable, or if quantification is inappropriate, described in qualitative terms. The most important of these aspects include the following:

1. Pollution data relating to pertinent variables and levels of emission.

2. "At-least" values of intangible effects.

3. Regional benefits or costs (unless prescribed as a direct project benefit).

4. All other project effects not measurable in any quantitative terms.

Basic Assumptions and Concepts of Cost-Benefit Analysis

The concept of cost used in this paper is that of "opportunity cost." An opportunity cost is the cost of not using a good or service in its next best use, and may be monetary or otherwise. For example, the "opportunity cost" of a factor of production is monetary, but that of a scenic natural area may be intangible.

A benefit is represented by a direct economic gain, the elimination of a cost, or a prescribed benefit such as a balance-of-payments improvement.

Benefits and costs are measured on an incremental (marginal) basis--the increment is the value of an increase or decrease in the output level of the unit under measurement. For example, benefits result from an increase in the output of a good or service, as well as from a decrease in the level of environmental pollution.[3]

In compiling project costs and benefits, all effects on society as a whole must be considered. Total project benefits and costs represent the sum of costs and benefits to all individuals, or groups of individuals, affected either directly or indirectly by project implementation.

In a full-employment economy, all shifts in the utilization of factors of production that do not contribute to the incremental change, but that occur as a result of this change, are considered offsetting. Such shifts are assumed necessary for the economy to achieve the new point of equilibrium. Nonincremental factor shifts are therefore ignored, since their net impact in terms of overall economic efficiency is zero.

All goods and services produced as a result of any research project and all factors of production have a value only to the extent that there is a need and demand for them. The market price reflects this need and demand most accurately and should be accepted as the value to the degree practicable. Eckstein (8, pp. 24-25) describes this valuation operation as follows:

> Costs are determined by factor prices and by the technical conditions of production, where factor prices reflect consumer's willingness to supply the factors as well as the value of the factors in the production of other commodities. . . . The benefit of a commodity is simply its value to the consumer. But in equilibrium the consumer will spend his income in such a way that the marginal rates of substitution are equal to relative prices, that is, the relative values of commodities at the margin are equal to the relative prices, and if we pick one commodity as a common denominator for the relative prices and benefits, we can say that the resultant absolute benefit of a commodity is equal to the price which the consumer pays. Thus benefit is a measure of value and reflects consumers' willingness to allocate income to the purchase of the commodity. . . .

All specific goods and services should be valued on the basis of market prices expected to prevail at the time costs are incurred and benefits realized. However, a constant average price level should be assumed for each project time horizon. Such an assumption neutralizes the impact of any general inflationary or deflationary trends, trends which increase or decrease

[3]For a discussion of increments to the national dividend in terms of marginal social net product and marginal private net product, see Pigou (16), especially pages 131-135.

the monetary value of projects' costs and benefits without affecting their value in relation to other products.

Applied research costs should be determined by the most accurate means available, such as project appropriations, or, when different from appropriated funds, actual disbursements.

Internal rate of return is the objective function to be maximized, and the measure by which projects are to be ranked. These rates are to be calculated for all costs and benefits measurable in dollar terms by reducing the value of future net benefits to a present worth of zero. This is explained in detail in the following section.

THE MEASUREMENT OF COSTS AND BENEFITS

Direct Benefits and Costs

Bureau of Mines applied research projects are undertaken in response to anticipated needs in mineral supply and demand and are designed to result in a technology which will permit (1) a cost reduction in producing an existing product and/or (2) the development of a new product, a better product, or a new use for an existing product. In such cases, the direct benefits are measured by the estimated incremental output of the associated good or service, less associated costs.

Eckstein describes the calculation of benefits (in a full-employment economy) as follows (8, pp. 24-25):

> The term "benefit" has been applied on a per unit basis, corresponding to price. More commonly, it is used for a specific quantity of a commodity, analagous to the concept of total revenue. Thus we speak of the benefit of, say, 10 units of X; if the price of X is \$3, the benefit of the 10 units is \$30. . . . Thus a certain change in design of a dam may add 10,000 units of output which may be worth \$3 each. The benefit of the change will be \$30,000. According to the fundamental rule of profit and welfare maximization, the change should be undertaken if its costs is less than or equal to \$30,000. . . . We can then . . . . say that marginal benefits must equal or exceed marginal costs, and apply it to whatever may be the smallest possible quanta of decision making.
>
> <u>This rule must be applied to all marginal production decisions in the economy, whether they are made by private or by public enterprises.</u> In the former case, profit maximization will drive firms to abide by the rule; for public undertakings, attainment of an efficient allocation of resources requires that the Government agencies devise their project plans and make their project choices on the basis of criteria which produce the same result. (emphasis added)

Under full employment and free market conditions, an increase in national efficiency occurs only with an increase in the output of some good or service; the benefit of the increased output is its value in the marketplace.

An increase in production represents the shift of economic resources to a more efficient use, benefiting both consumers of the output and the factors of production that represent the inputs necessary to obtain the increase in production.

To attract consumers, economic inputs utilized in producing the incremental output must be more efficient in satisfying the consumers' wants and needs than economic inputs employed in the production of present alternative outputs. When this greater efficiency occurs, consumers benefit to the extent that they shift to the new production. The value of this benefit is measured by what consumers are willing to pay--the worth of the incremental output in the marketplace.

Factor income increases to the extent that factor value increases. Producers bid for needed factors of production to attract them from alternative uses by offering a price in excess of what these factors previously obtained in their next best alternative employment; this excess price is the factors' opportunity cost. Producers are able to pay a higher price because increased factor efficiency in the new use (as opposed to the next best alternative use) justifies the increase.

The gross benefit of an increase in production is the sum of the benefit to the consumer plus the benefit to the factors of production. Associated costs (producers' payments to necessary factors of production) must be deducted from the gross benefit to obtain net benefit, the benefit to the consumer of the new output.

If the incremental production is an inefficient alternative, consumers will not purchase the output, and producers, in turn, will not receive an adequate rate of return on their investment. In this case, producers will return to previous levels of production, and factors engaged in producing the inefficient incremental output will return to alternative endeavors.

A recently completed study Department of the Interior (4) illustrates the measurement of expected direct benefits. The objective of the study was to evaluate two alternatives (shale oil and crude oil) for meeting the Nation's future oil needs in terms of present value.[4] Basically, estimates were made of net benefits added to the economy by each alternative.

---

[4]The concept used in this evaluation is the "with and without" principle--the identification of costs and benefits which result from a change in the path of the economy occasioned by a particular project. Application of this principle forecloses a fallacious use of the "before and after" comparison, a comparison which may credit a project with effects which occur only because of the passage of time or for other reasons irrelevant to project evaluation.

Direct benefits stem from actual production. And since consumers have no preference between shale oil and crude oil at identical prices, shale oil will be produced only when it is as cheap or cheaper than crude oil. Therefore, the direct benefit of shale oil research designed to provide the basis for economic production is the present value of the net returns created by estimated shale oil production. (In no case is the cost difference between alternatives the measure of project benefits.)

An analogy to a problem in dam construction is useful for illustrating the correct procedure for measuring direct benefits. Given that a dam is needed in a specific site (given that more oil should be produced), which is the more efficient alternative, dam A or dam B (crude oil or shale oil)? After determining the costs and benefits of constructing dam A (producing crude oil) and the costs and benefits of constructing dam B (producing shale oil), the two alternatives can be compared in terms of their respective benefits and costs.

Unlike the dam example, however, the oil shale analysis is not a matter of comparing proposed alternatives; rather, a proposed alternative is compared with an existing alternative or alternatives.

Therefore estimating benefits for oil shale requires a judgment of the marketability of products derived from shale oil. It is not necessary, however, to determine production costs of all possible competing goods. All that is required is to determine when technology would permit shale oil to sell at a competitive price--a price which permits market penetration and also provides a competitive rate of return to prospective investors.

In the study described, all costs and benefits were evaluated in terms of the common denominator of dollars. The dollar measure is most convenient, but in some cases direct benefits and costs[5] are only quantifiable in terms other than dollars. For example, measurements of water flow or user-days are available, but the monetary value of such terms is unknown; these terms are called incommensurables. While they are beyond the scope of this paper, methods are available to utilize physical data in cost-benefit analysis.[6] Unless there is no other alternative, incommensurables should not be relegated to the category of "intangible benefits and costs" (which are discussed in a later section).

It is emphasized that direct benefits are the net benefits of the incremental output associated with a specific alternative, not the <u>net</u> difference in benefits between the superior and the next best alternative.

---

[5]Or spillover effects. See the following section.

[6]Hitch and McKean, (<u>11</u>, p. 182), describe effects not measurable in dollar terms as "incommensurables," and those not measurable in <u>any</u> appropriate quantitative terms as both "incommensurable" and "intangible." For another discussion of incommensurables see Devine (<u>23</u>). Alternatively, the "at least" method described in this paper can be utilized.

External or "Spillover" Effects

McKean, in his book on benefits and costs (14, pp. 134-135), describes spillover effects as follows:

> Spillover effects . . . are impacts of actions by some decision-making units on the activities of others, impacts that are not directly felt by the first group. In economics, such spillovers are often labeled "external economies" and "external diseconomies." These terms sometimes refer to changes in the costs of a firm resulting from an expansion to the rest of that industry. In a more general sense, they refer to uncompensated effects on the costs or receipts of one group of firms caused by the actions of any other set of firms. As explained before, the term "spillover" is used here to embrace all of these types of external effects, whether they are economies or diseconomies, whether the cause is an industry's action or a Government investment, whether the effect is on a branch of the Government or an individual.

McKean distinguishes two types of spillovers, pecuniary and technological.

Pecuniary Spillovers

Pecuniary spillovers, the impact of actions by one group on the activities of other groups, are consequences that do not affect the units of output that can be obtained from a firm's physical inputs. McKean classifies pecuniary spillover into four groups (14, pp. 137-141): (1) Bidding up factor rates of hire; (2) cutting down prices of substitute products; (3) raising prices of complementary products; and (4) lowering the price of the output.

The concept of pecuniary spillovers is illustrated by the following example:

Assume that, as industry X implements the results of an applied research project, industry Y (producers of a competitive good) drops the price on its output in an effort to minimize or prevent the loss of markets to industry X. The annual production figures of industry Y, without and with a price decrease of $0.50 per unit (all figures assumed), are as follows:

	Price	Production, units	Capital costs	Operating costs	Total costs	Revenue	Profit
Without.......	$3.00	$10.00	$10.00	$10.00	$20.00	$30.00	$10.00
With..........	2.50	10.00	10.00	10.00	20.00	25.00	5.00

As shown in these new figures, producers have reduced their profits by $5 in order to absorb the decline in revenue; the industry cash flow has been

reduced $5, and in theory the industry now has $5 less to reinvest in new facilities.[7]

Consumers of product Y may now purchase the output at a lower per-unit cost. The price reduction, therefore, benefits consumers of product Y by $5.

The above situation shows a transfer of income, which favors current consumers at the expense of future investment in industry Y. No increase in economic efficiency has occurred. Through the workings of the marketplace, the lowered rate of return discourages additional investment in product Y because of the new competition from product X. An income transfer of this type is not a project benefit. To be regarded as a benefit, the explicit assumption must be made that society values a given sum of money in the hands of consumers more highly than in the hands of investors. This in general cannot be assumed, and the transfer must be treated as an offsetting shift in economic resources engendered by the decrease in the price of product X .

The question might be asked, What if the reduction in the price of product Y also leads to an increase in its output; is this not a benefit? The answer is no, for no increase can occur if all firms in the economy are in a least-cost position, which is the position any rational firm would strive to achieve. Therefore, in the absence of a real cost reduction (the case in pecuniary spillovers), any price cut by industry Y reduces cash flow, and hence the rate of return. This, in turn, reduces industry ability to attract new investment funds with which to expand (investment funds would flow to industry X and other industries offering more attractive rates of return). Over the long run, in absence of an offsetting technological advance, industry Y has no choice but to seek a new equilibrium at a point where production levels just reflect the increased competitiveness of product X.

This is classified under McKean's second category--cutting down prices of substitute products (from industry X's point of view). No examples of the other categories are presented, because it is felt the example given adequately illustrates the concept of pecuniary spillovers. It is important to remember that pecuniary spillovers are not included in project cost-benefit calculations.

Technological Spillovers

Unlike pecuniary spillovers, there is little doubt that technological spillovers--those which affect the physical outputs that other producers can get from their physical inputs--should be included in all cost-benefit calculations. Several different types of technological spillovers are described in the following sections.[8]

---

[7]In any accounting year, depreciation and profits, when added together, equal cash flow.

[8]Only the major technological spillovers are considered. In practice, many technological spillovers are too trivial or nebulous to warrant attention.

On Other Industries

The adaptation of research results by industries other than the one to which the research project is primarily oriented is of course, the most obvious technological spillover. Technological spillovers may affect the production possibilities of a variety of industries, both competitive and noncompetitive. The only test is that the resulting costs or benefits be specifically attributable to the project.

Using an industry X-industry Y example, let it be assumed that, as in pecuniary spillovers, the price of product X drops $0.50 per unit because of research on product X. This time, however, price drops because a technological advance occasioned by industry X research is also adopted by industry Y. The resulting increase in efficiency allows industry Y to pass along a cost savings in the form of a price reduction. Also, unlike the pecuniary spillover example, the real cost reduction allows industry Y to remain competitive in capital markets, thus able to increase output in order to achieve their new least-cost position.[9]

In this case, "without" and "with" production figures of industry Y are as follows (it is assumed that production increases one unit after the price decrease):

	Price	Production, units	Capital costs	Operating costs	Total costs	Revenue	Profit
Without.......	$3.00	10	$15.00	$10.00	$25.00	$30.00	$5.00
With..........	2.50	11	15.00	5.50	20.50	27.50	7.00

Here, the increased output of industry Y represents a spillover benefit of the industry X research project. The benefit is the value of the incremental output (1 unit) less associated costs. In this case, one unit is worth $2.50; associated costs are $0.50 per unit; and the net benefit is $2.

The $0.50 increase in operating costs represents the opportunity cost necessary to obtain new goods worth $2.50. Capital costs are not included in incremental costs, because industry Y production is assumed to be below capacity. In such a case, capital costs represent sunk costs,[10] existing whether or not the extra unit is produced. This example of a firm operating below capacity is not meant to be taken as a typical case, and is used for purposes of simplification only. When additional capital costs are involved (a firm

[9] Note the supplementary role that possible technological and pecuniary spillovers play in determining the ability of product X to increase output. Pecuniary spillovers tend to decrease the reaction ability of industry Y, and serve to increase the direct benefits flowing from industry X. Technological spillovers, on the other hand, tend to increase the competitive position of industry Y, decreasing the direct benefits from industry X, but increasing project spillover benefits as industry Y also expands production.

[10] See Hitch and McKean (11, pp. 172-173) for a brief but penetrating discussion of the treatment of sunk costs in cost-benefit analysis.

operating at capacity), they are, in effect, spread over the total volume of additional production and are reflected in the internal rate of return.

The major distinction between this example and the previous pecuniary spillover example is that real costs of product Y have decreased, and therefore producers of both product X and product Y have gained. The tabulation's total costs column reflects this real gain. In the pecuniary example, the total costs of industry Y are \$20 in both the with and without examples; in the technological example, the total costs of industry Y decline from \$25 to \$20.50.

Without the additional unit of goods, no national benefit would result, only a transfer of income. The factors of production decline in value by \$5, and consumers of product Y benefit by \$5. As in direct benefits, output must increase, and the resulting benefit is the value of this output in the marketplace, less associated costs.

Other Technological Spillovers

Production activities not directly related to the output of goods and services, but which affect other economic units or society as a whole must be considered. Although these external effects can be either costs or benefits, they are most often costs. Such external costs are borne by society whenever some private firm (or public agency) is able to avoid paying directly for costs and passes them on to other economic units--either consumers or other private firms.

The objective of cost-benefit analysis in this area is to determine the external impact of applied research projects, and to treat such impacts as project costs or benefits.

From the types of projects undertaken by the Bureau of Mines, such external technological spillovers commonly involve (1) changes in the existing levels of air, water, and land pollution, and (2) changes in existing health and safety conditions.[11]

Changes in Pollution Levels.--If factory X, located on a river, emits industrial waste into this river, the economic inputs of firms and consumers located downstream increase in cost. Other water consumers (such as municipalities, plants, farmers) must now pay more for inputs to clean up their outputs (drinking water, agricultural and manufactured goods), resulting in increased output cost. In this case, then, factory X has inflicted external costs on downstream users.

[11] Project orientation is the prime consideration. When project objectives are oriented towards increases in the production of goods and services, ensuing changes in health and safety conditions represent technological spillovers. When projects are primarily oriented towards improving health and safety conditions, such improvements represent direct benefits. This is mainly a classification problem, however, as the benefits or costs are measured similarly in either case.

Neglect of external costs will cause resource misallocation, a barrier to economic efficiency. For example, if firm X neglects the external costs associated with waste emittants, its decision as to how much to produce and what technology to use is correspondingly affected.

If a firm neglects external costs, it may produce too much or employ a technology that is excessively wasteful. The incremental cost of producing another unit of goods may be greater than the market price of that good. In this case, when all costs of production are considered, society is giving up other products, that could have been produced in return for a unit of goods which is less valuable. The result is resource misallocation.

The use of water, land, and air as natural resources assumes two value dimensions: environmental support and waste disposal, both necessary and useful functions. However, owing to the limited nature of these resources, the increased use of one function can often occur only at the expense of the other. At some point, the benefits to be obtained from the increased use of one function will be exceeded by the costs incurred from the decreased use of the other; from a strictly economic point of view, it is at present difficult to say precisely when this point is reached.

However, recent actions and statements of the Legislative and Executive Branches of the Federal Government, as well as of other public bodies, indicate that the public in this country is opting for more stringent pollution control. Therefore, it is assumed that any action which decreases the need to employ our water, air, and land resources in their waste disposal function can be treated as a benefit, and any action which increases the use of the waste disposal function as a cost, unless specific economic analysis shows otherwise.

The necessity for relying on the political process as a proxy for empirical analysis of pollution's cost-benefit effects is highlighted in a recent study by Ridker on air pollution (17, p. 159):

> Admittedly, without an estimate of the pollution costs, the policymaker must base his decision solely on his assessment of the financial burden the electorate will bear. . . . As an interim solution, reliance on the legislator may not be at all undesirable. Since elected representatives, more than any other segment of our society, are attuned to the attitudes that form psychic costs, and since psychic costs are likely to be a large portion of total costs, their assessment may not be too far from the mark. In any event, given the experience of this study, there may be no other solution available for some time to come.

Not only the field of pollution, but indeed the entire spectrum of technological externalities, is fraught with barriers to meaningful quantification. Brooks comments (21):

> We are unfortunately a long way from being able to measure all external costs. Even the effects on other industries, which are relatively easy to get at, have seldom been evaluated. . . . We certainly have little idea what most people would be willing to pay to avoid damages to natural terrain, and we are just beginning to get some ideas on how they value recreation resources.

Despite these difficulties, a system of measurement can be devised to provide, at least, an order of magnitude indication for potential benefits and costs and a base of empirical data which may, at a later date, be blended into a more meaningful measurement system.[12] One phase of this measurement system is to establish geographic boundaries within which the pollution sources under analysis are expected to have their major impact. Once the pollution impact boundaries are established, the size and value of certain variables can be determined--variables such as population, crops, and livestock--which are believed to be affected by changes in pollution level. Quantification of the variables can then be used to provide some order of magnitude indication for resulting benefits or costs. For example, given that a certain type of air pollutant inflicts damage on cattle, an X amount of increase in this pollutant will result in greater external costs in an area in which 1,000 cattle are located than in an area in which only 500 are located. A detailed discussion of developing the necessary methodology and data for implementing this system is given in appendix A.

Pollution Standards.--Pollution standards establish certain levels of pollution emission in a given area. Economic units located in the affected areas must confine their emission rate to a level specified in the standard.

A variety of public bodies are, or will be, involved in establishing and enforcing standards. For water, each of the 50 States is currently developing standards with the assistance of the Federal Government. For air, many States and lesser jurisdictions are considering, or implementing, a variety of standards. The Federal Government may eventually establish national standards for certain types of air pollutants, and indeed, has already done so in the case of automobile emissions. Efforts to control land pollution (for example, solid waste and strip mining activity) are contemplated or in existence in different areas.

Standards serve to internalize previously external costs, and such costs are quantified and become subject to a firm's profit and loss calculations. Therefore, when standards exist, the entailed costs necessary for compliance are available, and may be included in project operating and capital figures under direct costs. Any proposed projects which contemplate the creation of an emission level of such magnitude as to render either present or future compliance economically or technologically infeasible will, of course, not be acceptable for funding.

[12] The concept of "collective goods" is a major justification for Government actions in our economy. Since the subjects discussed in this report under "Other Technological Spillovers" are "collective goods," it becomes especially important for the Bureau to achieve some degree of quantification in this area. For a brief discussion of "collective goods" and the accompanying need for Government initiative, see Dorfman (7, pp. 4-5).

Any given standard should not be treated as a permanent feature. It is expected that pollution standards will be revised from time-to-time as enforcing bodies gain additional knowledge, as pollution abatement technology improves, and as public attitudes towards environmental quality fluctuate.

It is necessary to remain cognizant of these likely changes. As standards are revised they may change previously computed project benefits and costs or involve a time period of some length for emitters to achieve compliance. Care must be taken to allow for any resulting external costs during the period before compliance.

Changes in Existing Health and Safety Conditions.--Improvements in working conditions create benefits by increasing the quality of the working environment.

A primary objective of health and safety research is to reduce the incidence of on-the-job accidents. These accidents create costs in the form of (1) hours lost from work, (2) disability of a severity sufficient to prevent resumption of the same job, and (3) death.

Although a reduction in accident rates creates benefits not fully measurable in monetary terms, a portion of these benefits is measurable--the value of reductions in sick pay, disability pensions, death benefits, widow pensions, and any other payments made as a result of temporary incapacitation, permanent disability, or death.

A system of measurement can be illustrated for benefits from accident reduction. Industry X implements research results. The preproject accident rate caused an average of 100 hours lost from work per year, at an average hourly rate of $2; postproject rates are expected to average 90 hours per year, at a rate of $2 per hour. The benefit derived from accident reduction is 10 hours per year at $2 per hour, or $20 per year. This annual benefit is to be applied to each year of the project time span, less associated costs--the costs of implementation.

Any intangible (nonquantifiable) benefits of the change, such as avoidance of death and improved worker morale, should be described in qualitative terms under the section on intangible benefits.

Secondary Benefits and Costs

Secondary benefits and costs are the expansionary effects of project direct benefits. They differ from external costs and benefits in that they are compensated shifts in economic resources; that is, they would occur in any event, regardless of project implementation, though not necessarily in the same locale.

Secondary benefits are the benefits of increased employment, income, and investment, and they occur because of the multiplier effects of money flows. The multiplier effect is the ratio between an increase or decrease in income, and an increase or decrease in new capital formation.

Secondary national benefits are not usually included in applied research cost-benefit calculations. Secondary regional benefits are normally calculated and submitted as supplementary material, and, as such, are not included in project cash flows or final calculations unless specifically identified as a prescribed benefit.

Secondary National Benefits

Cost-benefit analysis assumes "full-employment" conditions for the economy.[13] Such an assumption is consistent with the near "full-employment" conditions of much of the postwar period. Under such conditions, secondary project effects represent only the shift of resources to alternative activities or locations with no corresponding increase in efficiency.

Under conditions of near "full employment," the calculation of secondary benefits is not undertaken for the following reasons:

1. As only a few resources will be unemployed or underemployed--and perhaps for only a portion of the project's time span--any resulting benefits will be quite small in relation to total project benefits. Secondary national benefits assume an important role only when a significant portion of all natural resources are projected to be idle over most, or all, of the project's time span, and when the project will employ previously unemployed resources.[14]

2. Uncertainty creates difficulty in projecting the rates of change in resource utilization attributable solely to the research project. For example, it cannot be *a priori* assumed that presently unemployed resources will remain so in the absence of a particular research project. Such assumptions require considerable knowledge of other pertinent variables including Federal fiscal policy and other proposed or planned public and private expenditures. This requires analysis of detail on such scale as to render the results not worth the effort in "good times." In addition, the unavoidable uncertainties can raise questions about the accuracy and meaningfulness of any resulting calculations.

Therefore, cost-benefit analysis assumes "full employment." Such an assumption classifies secondary national benefits as offsetting interregional transfers.

---

[13] Full employment is the condition that exists when all who are able and willing to work can find renumerative employment. Persons laid off or changing jobs cause a certain amount of frictional unemployment at all times. As long as those in this status do not exceed 3 to 4 percent of the labor force, full employment is generally agreed to exist.

[14] In economic terms, employment of previously unemployed factors of production involves no social cost. Methods have been devised to evaluate projects undertaken in less than full employment conditions, but they are beyond the scope of this paper. For a discussion of these methods see Haveman and Krutilla (24).

Secondary Regional Benefits

Regional benefits are not normally included in the summation of a project's benefits unless the regional benefits become prescribed benefits. Regional benefits, however, represent real gains to the areas involved. To allow for appropriate consideration of these gains in the evaluation of applied research projects, potential regional benefits can be measured as a supplement to a cost-benefit study. Any expansion in local employment and income, as well as any additional local investment, occurring as a result of the project are to be counted. To do this, two types of effects must be distinguished--one-time and continuing. One-time effects consist of increases in employment and wages in the local area due directly to the project (normally the construction period). Continuing effects are the indirect results of the project, and consist of supplementary economic expansion brought on by the existence of the project, including the following items:

1. Increases in jobs and payrolls (other than those occurring as a direct result of the project).

2. Present per-capita income.

3. Present unemployment rate.

4. Expansions in local business establishments and the creation of new establishments.

5. Improvements in, or expansion of, local infrastructure, including highways, railroads, docks, and piers, and also airports.

Intangible Benefits and Costs

Intangible benefits and costs are those project effects which are unmeasurable in any objective and generally accepted terms.[15]

Care should be taken in classifying project effects as intangibles. The tendency to overload this category at the expense of measurable-item categories is a common one. In actuality, the number of completely intangible effects may be very limited.

There are many project effects whose absolute values may be in principle unmeasurable. However, in a relatively limited context these effects can be included in tangible benefit categories by treating them as explicit project requirements. Kneese (13), referring to water pollution control programs, states:

> This can be done by initially treating . . . goals, expressed in physical terms, as limits or constraints upon the cost minimization objective. . . . Conceivably this would require a very different combination of units with different operating procedures than a

[15]See footnote 12.

> system designed without constraints. Presuming the constrains are effective, i.e., - not automatically met if costs are minimized, they would result in a higher cost system than could otherwise have been achieved. The extra cost represents the limitation which the constraint places upon the objective.

By making intangibles, such as social goals, explicit in this manner, we may calculate their minimum, or "at-least," value. Kneese (13, pp. 34-35) explains "at-least" value by the following:

> One useful way of stating the results of variation of constraints which represent goals . . . not valued directly by, or imputable from, the market . . . is in terms of what they must "at least be worth". . . . [By] comparing the optimum system with and without the constraint, it is possible to indicate what the LEAST value is that must be attached to the increment of pleasure in order to make that level of control procedures worthwhile.

In mining, for example, esthetic considerations may require an underground, rather than an open-pit system, the least (private) cost system, for a given operation. The esthetic values so preserved must be worth, in dollar terms, at least the equivalent of the increased mining costs incurred.

The "at-least" system of evaluation, according to Brooks (20, p. 37), means that,

> We are in fact putting a monetary valuation on aesthetic or social goals whether or not we like to think of it that way . . . Any restriction or regulation that is placed on . . . mining . . . implies an evaluation. Each has an economic cost that can be made explicit, and . . . the social benefits to be gained by imposition of the requirements . . . [should be] worth AT LEAST this much.

Intangible benefits under improved health and safety conditions might include a decrease in lives lost, the avoidance of discomfort and pain, improved peace of mind on the part of worker families, improved worker morale, increased ability on the part of industry to recruit new workers, improved labor relations, and the accrual of general "good will" to the industry.

All possible incommensurable and intangible effects cannot be neatly categorized. Their scope and impact will vary with the particular project. These effects should be described as fully as possible to allow for their subjective incorporation into the final decision-making process. Incommensurable effects should be quantified by the "at-least" method and submitted in a section along with other qualitative aspects.

Prescribed Benefits and Costs

Certain project effects will create costs and benefits only when the effects are explicitly stated as objectives by the appropriate decision makers.

In this category are events which are not normally considered by cost-benefit analysis, or in lieu of specific assumptions, not deemed national in scope and are automatically excluded from project calculations. Some of the more common of these prescribed effects are balance-of-payments and national security effects. When these effects are made explicit project goals they must be quantified to the degree practicable.

Another example of a prescribed effect is regional economic improvement. While these effects are normally quantified, they are not reflected in project internal rates of return. Therefore, when such effects become a prescribed goal, the only additional step required is to incorporate regional benefits and costs into the final project calculations.

In some cases, the benefits such as national security may not be measurable, or commonly they will be quantifiable but not commensurable with other project benefits and costs. However, the cost side is normally quantifiable in monetary terms and therefore subject to cost-minimization.

COST-BENEFIT CALCULATIONS

Once all benefits and costs are calculated, three additional steps are necessary to obtain final project figures.

The first step is to determine the acceptance of project results by private investors. For this step, the project is assumed to be successful. Second, the probability of success allowance is determined. And, finally, the internal rate of return must be calculated. It is assumed in the following discussion that direct benefits will be obtained only through industrial production following Government research; in some cases, benefits may rather require action by another public agency, but this does not alter the principles involved.

The following tabulation will be used throughout for illustrating the necessary calculations:

Project X, Implemented by Industry Y[1]

Year	Private costs	Project costs	Benefits
1.................	-	$25,000	-
2.................	$100,000	20,000	-
3.................	125,000	10,000	$100,000
4.................	100,000	5,000	150,000
5.................	80,000	-	200,000
6.................	40,000	-	200,000
Total........	445,000	60,000	650,000

[1] These figures do not include social costs and benefits. Such figures will be introduced at the appropriate time.

Industry Acceptance

Normally, an industry will implement, or accept, the results of an applied research project only when the required investment promises to yield a rate equal to, or greater than, what is considered the normal rate of return available from alternative investment opportunities.

Such factors as the market rate of interest and industry elasticity of demand, when combined with other considerations, have enabled most industries to determine their normal rate of return[16] Industry will avoid investments which yield a rate below this normal rate, unless nonfinancial considerations are involved, such as a new Government regulation. If, when all project benefits and costs are discounted at a rate equivalent to the industry's normal rate of return, the project has a positive present value, it will be implemented.

The industry evaluation will normally involve only private costs and benefits (not Government research costs and not external effects). Also, the evaluation will cover only the time span applicable to potential private investors. This time span will in all cases be shorter than the overall project time span, because industry will begin investing only at some point after culmination of the research effort.

Following is an example of the necessary calculations: Project X, when implemented by industry Y, is expected to create the following direct private costs and benefits[17] over the project time horizon. The total costs of implementing the project are $445,000 and the benefits are $650,000. (These figures do not include Government research costs.)

Private costs and benefits		
Year	Costs	Benefits
2	$100,000	-
3	125,000	$100,000
4	100,000	150,000
5	80,000	200,000
6	40,000	200,000
Total	445,000	650,000

All benefits and costs must now be discounted at industry Y's normal rate of return, assumed to be 10 percent.

---

[16]For a treatment of the normal rate of return in the oil industry, see Solomon (18).

[17]Direct costs and benefits are used exclusively here. Project external costs or benefits do not normally enter into industry calculations. One exception is in the necessity of complying with pollution standards. Even here, however, the costs necessary to achieve compliance will be included in capital costs, and therefore reflected in direct project costs.

Present Value

(Benefits and costs discounted at 10 percent)

Year	Costs	Benefits	Net benefits
2....................	$90,900	-	-$90,900
3....................	103,250	$82,600	-20,650
4....................	75,100	112,650	+37,550
5....................	54,640	136,600	+81,960
6....................	24,840	124,200	+99,360
Total...........	348,730	456,050	+107,320

The discounted figures indicate a positive present worth of $107,320. Therefore, the project offers a rate of return greater than 10 percent and will likely be implemented by industry.

Probability of Success Allowance

The probability of the success allowance factor, used in evaluation of applied research projects, is not unlike the industry acceptance procedure just described.

At any time there exist alternative applied research opportunities, each with its own probability of achieving success as measured by net returns. It is necessary to make allowance for these varying probabilities if projects are to be evaluated on an equal footing. Therefore, estimated project benefits are reduced by an appropriate factor, in effect converting estimated benefits to mathematical expected values.

An important tool in probability calculation is the agency's target rate of return.[18] It must be determined prior to analysis and used as a common parameter for all evaluations undertaken at one time.

To calculate the minimum probability of success figures for a project, subtract the undiscounted private costs from the undiscounted benefits to obtain net private benefits. Next, the probability of success level is determined that renders net benefits exactly equal to costs, when both are discounted at the target rate of return. The probability of success level can then be compared with an expert's judgment of the project's promise of success. If the minimum success level is higher than the expert's judgment, no further analysis of the project is needed; when the expert's judgment is higher, it is used in the subject analysis.

[18]In principle, the target rate of return should equal the agency's marginal internal rate of return. See Vogely (19, p. 31).

The time stream of project net private benefits is reduced by the residual of the promise of success figure--the promise of nonsucess figure.[19] The reduced benefit figures are then used in the internal rate of return calculations.

Using the previous product X-industry Y example again to illustrate these calculations, net private benefits equal the net benefit figure obtained by subtracting undiscounted private costs from undiscounted private benefits, as follows:

Year	Private costs	Private benefits	Net private benefits
2....................	$100,000	-	-$100,000
3....................	125,000	$100,000	-25,000
4....................	100,000	150,000	+50,000
5....................	80,000	200,000	+120,000
6....................	40,000	200,000	+160,000
Total...........	445,000	650,000	+205,000

The next step is to discount the net private benefit stream at the appropriate target rate of return (assumed here at 7 percent), and compare the total to Government costs discounted at the same rate. This calculation follows:

Year	Net private benefits	Net private benefits, present value at 7 percent discount	Project costs	Project costs, present value at 7 percent discount
1..........	-	-	$25,000	$23,375
2..........	-$100,000	-$93,500	20,000	17,460
3..........	-25,000	-21,825	10,000	8,160
4..........	+50,000	+40,800	5,000	3,815
5..........	+120,000	+91,560	-	-
6..........	+160,000	+114,080	-	-
Total.	+205,000	+131,115	60,000	52,810

Once this calculation is completed, it becomes relatively simple to determine the minimum probability of success level, which in this case is the ratio of $52,810 (Government project costs) to $131,115 (private benefits), or 0.403. If the expert's judgment of probability of success is higher than 0.403, the sum of the discounted net private benefit flow will be positive for the project. The assumption in this case is that the expert's judgment is 0.833. Now the time stream of undiscounted net private benefits must be reduced by the promise of nonsuccess, assumed to be 0.167.

[19]A project's promise of success level consists of two parts, the probability of success, and the probability of nonsuccess. The two when added together must equal 1.00. Thus, a project with a probability of success of 0.667 must, by definition, have a probability of nonsuccess of 0.333.

Year	Undiscounted net private benefits	Undiscounted net private benefits after deduction of probability of non-success allowance
2....................	-$100,000	-$83,300
3....................	-25,000	-20,825
4....................	+50,000	+41,600
5....................	+120,000	+99,960
6....................	+160,000	+133,280
Total...........	+205,000	+170,765

The undiscounted net private benefits of project X, after allowances for nonsuccess, are $170,765. Net private benefits, which includes both private benefits and costs, is the time stream discounted rather than gross private benefits. With this figure, internal rate of return calculations are undertaken.

Internal Rate of Return[20]

Applied research projects can be ranked by their internal rate of return. An internal rate of return is that rate of discount which makes the present value of net private benefits (after allowance for nonsuccess) equal to the present value of costs.

It is necessary to calculate three rates of return for each project: One using only direct benefits and costs; a second measuring the benefits and costs of increased output because of the adaption of research results by other industries (technological spillover); and a third, using both calculations, but also including other quantifiable technologic externalities such as land values and reductions in payments for lost work time. The first step is to deduct costs from the time stream of net direct private benefits to obtain net national benefits from the research project, as follows:

Year	(1) Net private benefits (after probability deduction)	(2) Government project costs	(3) Net national benefits from research project
1....................	-	$25,000	-$25,000
2....................	-$83,300	20,000	-103,300
3....................	-20,825	10,000	-30,825
4....................	41,650	5,000	+36,650
5....................	99,960	-	+99,960
6....................	133,280	-	+133,280
Total..........	+170,765	-60,000	+110,765

[20] There are a variety of ways for calculating project profitability. However, the internal rate of return was selected for ranking projects because it tends to approximate private market calculations more accurately than do other measurements. For a detailed discussion of time streams and criteria, including a treatment of the problem of interrelated investments and internal rates of return see McKean (14, pp. 74-93).

By subtracting column 2 from column 1 above, net national benefits from the research project are obtained. This time stream must now be reduced to zero to present value at time period 0 to obtain the internal rate of return.

By a process of trial and error, the internal rate of return is approximately 17.3 percent, as follows:

Year	Net national benefits from research project	Discounted net benefits	
		17 percent	18 percent
1....................	-$25,000	-$21,375	-$21,175
2....................	-103,300	-75,512	-74,169
3....................	-30,825	-19,235	-18,772
4....................	+36,650	19,571	18,911
5....................	+99,960	45,582	43,683
6....................	+133,280	51,979	49,314
Total..........	+110,765	+1,010	-2,208

A 17-percent rate of discount yields a value in excess of zero; and an 18-percent rate, a negative present value. By interpolation, the correct rate is approximately 17.3 percent.

For purposes of this example, it is assumed that project X employs a relatively unique technology, and therefore the research results are not adaptable by other industries. If they were, any ensuing benefits and costs would be added to direct benefits and costs to develop a combined internal rate of return. The next step would be to calculate the third internal rate, where quantifiable external costs and benefits are inserted into the appropriate flows.

For illustrative purposes, we assume the following: Project X involves the disposal of waste in a volume sufficient to occupy 100 acres of land per year. The next best use value of this land is $100 per acre. Therefore, project X creates external costs at the rate of $10,000 per year, for 5 years.

Project X also creates an external benefit in the form of health and safety improvements. Industry Y, after implementing this project, will experience a reduction of $3,000 per year in their current death and disability payments.

To prepare external costs and benefits for the internal rate of return calculations, net them out and reduce the remainder by the project probability of nonsuccess factor (0.167). The annual net figure of -$7,000 ($10,000 in external costs; $3,000 in external benefits), when adjusted for the probability of nonsuccess factor, is -$5,831; this figure is now inserted into the cash flow as follows:

Year	Original net national benefits from research project	Net external costs (adjusted for probability of success)[1]	New net national benefits from research project
1.........	-$25,000	-	-$25,000
2.........	-103,300	-$5,831	-109,131
3.........	-30,825	-5,831	-36,656
4.........	+36,650	-5,831	+30,819
5.........	+99,960	-5,831	+94,129
6.........	+133,280	-5,831	+127,449
Total	+110,765	-29,155	+81,610

[1]External costs and benefits do not begin until the second year of the project time horizon because this is the year when the project is actually implemented.

With these figures, an internal rate of return can be obtained:

Year	New net national benefits from research projects	Discounted net benefits	
		12 percent	13 percent
1..................	-$25,000	-22,325	-22,125
2..................	-109,131	-86,977	-85,450
3..................	-36,656	-26,099	-25,403
4..................	+30,819	+19,601	+18,892
5..................	+94,129	53,371	+51,112
6..................	+127,449	64,616	+61,176
Total.........	+81,610	+2,187	-1,798

A 12-percent rate of discount yields a value at time 0 in excess of zero; a 13-percent rate, a negative present value. By interpolation the correct rate is 12.6 percent. This completes the calculation of all needed rates of returns, which is the basis for ranking alternative projects.

The methodology employed in this report for calculating the costs and benefits of applied research is only one of several alternative approaches available. It was selected because it provides a relatively straightforward means of ranking alternative research projects on the basis of returns to the investment dollar. In the future, as experience is acquired in the evaluation of applied research, it may well be replaced or modified by alternative measurement systems.

BIBLIOGRAPHY

Government Publications

1. Johnson, Edward E., and Harold J. Bennett. An Engineering and Economic Study of a Gold Mining Operation. BuMines Inf. Circ. 8374, 1968, 53 pp.

2. Public Health Service. Air Quality Criteria for Sulfur Oxides. March 1967, 175 pp.

3. U.S. Congress. The Adequacy of Technology for Pollution Abatement. Hearings Before the Subcommittee on Science, Research, and Development of the House Committee on Science and Astronautics. 89th Cong., 2d Sess., July, August, and September 1966, 2 vol., 915 pp.

4. U.S. Department of the Interior. Prospects for Oil Shale Development--Colorado, Utah, and Wyoming. Washington, D.C., May 1968, 158 pp. (limited distribution).

5. U.S. Federal Inter-Agency River Basin Commission, Subcommittee on Benefits and Costs. Proposed Practices for Economic Analysis of River Basin Projects. Washington, D.C., May 1950, revised 1958, 67 pp.

Books and Pamphlets

6. Brock, Samuel M., and David B. Brooks. The Myles Job Mine--A Study of Benefits and Costs of Surface Mining for Coal in Northern West Virginia. Center for Appalachian Studies, West Virginia University, 1968, 61 pp.

7. Dorfman, Robert (ed.) Measuring Benefits of Government Investments, the Brookings Institution, Washington, D.C., 1965, 419 pp.

8. Eckstein, Otto. Water Resource Development, the Economics of Project Evaluation, Harvard University Press, Cambridge, Mass., 1965, 300 pp.

9. Friedman, Milton. Price Theory--A Provisional Text, Aldine Publishing Co., Chicago, Ill., 1962, 285 pp.

10. Herfindahl, Orris C. Three Studies in Mineral Economics, Resources for the Future, Inc., Washington, D.C., 1961, 63 pp.

11. Hitch, Charles J., and Roland N. McKean. The Economics of Defense in the Nuclear Age. Atheneum, New York, 1965, 422 pp. (Originally a Rand Corporation Research Study published by Harvard Univ. Press.)

12. Jarrett, Henry (ed.). Environmental Quality in a Growing Economy. Resources for the Future, Inc., Johns Hopkins Press, Baltimore, Md., 1966, 173 pp.

13. Kneese, A. V. Water Pollution--Economic Aspects and Research Needs. Resources for the Future, Inc., Washington, D.C., 1962, pp. 32-33, 42-44.

14. McKean, Roland N. Efficiency in Government Through Systems Analysis. John Wiley & Sons, Inc., New York, 1958, 336 pp. (A Rand Corporation Research Study.)

15. Novick, David (ed.). Program Budgeting: Program Analysis and the Federal Budget. Harvard Univ. Press, 1965, 382 pp. (A Rand Corporation sponsored research study.)

16. Pigou, A. C. The Economics of Welfare. Macmillan and Co., London, 4th ed., 1948, 876 pp.

17. Ridker, Roland G. Economic Costs of Air Pollution, Studies in Measurement. Frederick A. Praeger, New York, 1967, 214 pp.

18. Solomon, Ezra. The Financial Feasibility of Capital Expenditures for Oil Shale Development 1915-1920, and 1966. A special study for the U.S. Department of the Interior (unpublished), Stanford Univ., 1967, 73 pp. Summarized in Post Hearing Brief, Colorado 359, USA vs. F. W. Winegar, and Colorado 360, USA vs. D. A. Shale, Inc., v. 4, May 20, 1968, pp. A-882--A-905.

19. Vogely, William A. Measuring the Benefits of Minerals Research, Proc. Council of Economics, AIME, New York, Feb. 19-23, 1967, 421 pp.

Articles

20. Brooks, David B. Strip Mine Reclamation and Economic Analysis. Nat. Res. J., v. 6, No. 1, January 1966, p. 37.

21. _____. Strip Mining, Reclamation, and the Public Interest. American Forests, v. 72, No. 3, March 1966, pp. 18-19, 53-57.

22. Crutchfield, James A., Robert W. Kates, and W. R. Derrick Sewell. Benefit-Cost Analysis and the National Oceanographic Program. Nat. Res. J., v. 7, No. 3, July 1967, pp. 361-375.

23. Devine, E. J. The Treatment of Incommensurables in Cost-Benefit Analysis. Land Economics, v. 42, No. 3, August 1966, pp. 383-387.

24. Haveman, Robert, and John Krutilla. Unemployment, Excess Capacity, and Benefit-Cost Investment Criteria. The Review of Economics and Statistics, v. 49, No. 3, August 1967, pp. 382-392; v. 49, No. 3, November 1967, pp. 654-655.

25. Kneese, A. V. Socio-Economic Aspects of Water Quality Management, J. Water Pollution Control Federation, v. 36, No. 2, 1964, pp. 254-262.

26. Krutilla, J. V. Conservation Reconsidered. The American Economic J., v. 57, No. 4, September 1967, pp. 777-786.

27. Verner, William J., and Robert F. Schurtz. For Mine Evaluation--A Fresh Model. Min. Eng., v. 18, No. 11, November 1966, pp. 65-71.

APPENDIX A.--POLLUTION COSTS AND BENEFITS METHODOLOGY AND DATA REQUIREMENTS

Geographic Parameters and Susceptible Indigenous Variables

In order to subject pollution to cost-benefit analysis, different geographic boundaries must be established for each type of pollution, since the effects and impact areas of air, water, and land pollution vary significantly.

Air pollution tends to be a fairly localized phenomenon, confined to the airshed within which it occurs. Once an air pollutant is carried any appreciable distance from its source, sufficient dilution occurs to mitigate much of its harmfulness.

Water pollution tends to be a sequential phenomenon, with widespread effects, especially in the case of nondegradable pollutants. Streams of water are like conduits, carrying persistent types of pollution far downstream. As more pollutants are added to the water, the sequential effect takes over, and the level of pollution increases correspondingly.

Land pollution, such as solid waste from strip mining activities, generally affects only its immediate environs, because such types of pollution, unlike air and water, are relatively immobile.

Based on these considerations, the following geographic boundaries are suggested as appropriate for measuring potential external costs and benefits.

Air Pollution

In many urban air pollution studies, the pertinent airshed is considered analogous to the local SMSA (Standard Metropolitan Statistical Area). Therefore, for the purposes of uniformity and statistics gathering, when the source of the air pollution is located within the boundaries of an SMSA, these boundaries shall be considered the pollutants' geographical limits.

In areas where a SMSA does not exist, the county within which the source of pollution is located shall, in most cases, be the applicable boundary of consideration. In cases where it can be shown that commonly prevailing wind patterns will tend to spread the pollutant into neighboring counties on frequent occasions, all affected counties shall be the applicable geographic limits.

Water Pollution

In the absence of empirical evidence regarding the normal range of these water-carried pollutant effects (as well as the absence of the convenient statistical gathering parameters which exist for air pollution), a 25-mile limit is considered the appropriate geographic range; that is, 25 miles downstream from the source under consideration. All sources that draw water from the stream within this boundary should be specified as accurately as possible, from whatever sources available. For example, the municipalities using the stream as a source of drinking water can be determined and listed, along with

their population. At the minimum, a general description of the geographic area can be given, such as classifying it as generally urban or rural, and noting the extent of irrigation, existing and potential recreation facilities. In rural areas, it is usually common information if a few manufacturing plants are located along the river; the plants can easily be specified. In addition, manufacturing and agricultural information for the counties or SMSA's that border the river within the 25-mile limit can be presented as general background information.

Beyond the 25-mile limit, the potential effects of pollutants can only be treated in a marginal sense (especially in the case of nondegradable pollutants). The analysis for nondegradable pollutants should include the downstream length of the pertinent water body beyond the cutoff point, as well as other water bodies into which it may flow (if any) and their length. In the case of degradable pollutants, the estimated additional distance the pollutant must travel to be completely degraded, and the bodies of water it will affect, should be included.

Land Pollution

As these effects are localized, a description of the immediate environs of the pollution location should be included. If the solid waste gives off noxious odors, or is eventually disposed of by burning, such events should be considered under air pollution. If it is eventually disposed of by dumping into a water body, such events should be considered under water pollution.

Also, unlike air and water pollution, the external costs of land pollution may be partially quantified. This is done by determining the next-best use value of the land to be utilized for waste-disposal. Such quantification requires data on indigenous land values, estimates of the total acreage to be so used, and the annual rate of use. Order of magnitude concepts must, nonetheless, be utilized in treating esthetic costs inflicted on land surrounding, but not directly used in, the waste disposal function. Order of magnitude concepts must also be utilized to deal with esthetic or serendipity values[1] contained in the waste disposal land itself, values which may not be reflected in current market prices.

---

[1] Serendipity values are predicated on the existence in nature of a balanced ecosystem of which some components may not be presently known or utilized by man because of a combination of inadequate knowledge and technology. Therefore, the disturbance of any previously pristine area may inflict a serendipity cost of unknown proportions on society.

The serendipity value is clearly reflected, for example, in the recent decision of the British Government not to construct a military airbase on the Isle of Aldabra in the Indian Ocean, for fear of destroying a unique indigenous ecology.

For a more detailed treatment of the serendipity concept, see Krutilla (26), especially pages 780-781.

Data Needs

The following items are normal data needs for a typical geographic boundary. The data specified herein is tentative in nature, and may be subject to revision or expansion as further experience indicates.

1. Population

   A. Number

   B. Type

      (1) urban--specify the number and size of significant population concentrations

      (2) rural--farm

      (3) rural--nonfarm

   C. Age composition

   D. Employment compositon (agriculture, industry, mining)

   E. Flow--numerical estimates of nonresidents who enter the geographic area on a workday or other regular basis

2. Economic

   A. Agriculture

      (1) crops--type and value

      (2) livestock--type and value

   B. Industry--number of plants

      (1) by industry

      (2) by employment size

   C. Mining--number of concerns

      (1) by industry

      (2) by employment size

3. Miscellaneous

   A. Auto registration

   B. Recreational facilities

(1) boating and swimming

(2) parks--national, State, local

(3) other unique features--scenic and historical areas, unusual wildlife, etc.

(4) estimated annual tourist flow

In addition, any other data deemed pertinent to the particular project should be included.[2]

Measuring Changes in Pollution Emission

To measure the change in existing pollution levels, the following data should be compiled for all pollutants expected to be released as a result of the project:

1. Total volume of emission, by type.

2. The time span over which each emission will occur, commonly the project time horizon (except when such effects are expected to be of significance for some longer period).

3. Annual rate of emission by type (in some cases, this rate may be different at different points in the project time horizon. If so, they should be noted and explained).

4. The time when each type of emission will first occur.

It can be seen that in comparing alternatives to a project stipulated as the base effort, ensuing changes in pollution emission data could act as an indicator of relative pollution costs or benefits.

Potential receptors would receive benefits as items 1 and 3 decrease from the base effort, as item 2 increases, and as item 4 is moved further into the future.

Item 3 could be a key measurement. As the emission rate decreased, for example, potential pollution costs would also decrease in some amount relative to it. If a linear relation were assumed between emission rates and potential damage, then, of course, the decrease would be proportionate. While it is generally assumed that emission and damage are not linear as they move out from point zero, in the case of marginal analysis (an incremental change from any given point greater than zero), pollution-damage relationships are not presently defined with any great degree of confidence, and in some cases might well be linear.

---

[2]For a detailed discussion of the development and application of data in measuring pollution costs, see Brock and Brooks (<u>6</u>). (Underlined numbers in parentheses refer to items in the Bibliography preceding the appendixes.)

The data above should be, in most cases, sufficient to provide an acceptable empirical base. However, to the extent that the subject geographic boundaries contain environmental features of a unique or intermittently recurring nature, the data may not be completely satisfactory. Therefore, any meteorological, hydrological, geological, or seasonal features deemed peculiar to the area should be noted and explained; for such features may exacerbate the effects of estimated project emission levels.

In addition, when feasible, the private costs of purchasing and operating equipment to reduce or eliminate anticipated emisions should be included, indicating the degree to which each type of emission might be curtailed.

APPENDIX B.--THE HEAVY METALS COST-BENEFIT ANALYSIS--A CASE STUDY[1] [2]

The purpose of this project is to determine if an expenditure of public funds with the objective of increasing the supply of domestic gold is justifiable on economic grounds.

Towards this end, a cost-benefit analysis was undertaken for the project of (1) discovering and delineating new sources of domestic gold and (2) initiating research to improve the present state of gold mining technology.

Project background research indicated that Carlin-type and epithermal deposits were most likely to be discovered in significant quantities; that these deposits were amenable to open-pit mining; and that research oriented towards reducing costs in open-pit mining methods had a high probability of success.

Therefore, cost-benefit data were developed for four likely project outcomes based on the background research. These alternatives were both a minimum and a probable discovery rate for Carlin-type and epithermal deposits, with the amounts of contained commercial grade ore constrained by both present and more advanced technology.

Carlin-Type and Epithermal Deposits

Assumptions and Methodology

Throughout the study it was assumed that both epithermal and Carlin-type deposits lend themselves to open-pit mining. The optimum level of production was defined as that which provides the maximum return on investment, and, for a potential deposit of a given size, was derived from a mathematical mine development model. The coefficients of this model incorporate the various costs incurred in the operation of a 32,000-ton-per-day open pit gold mine, the original cost data for which were developed in a Bureau of Mines study by Johnson and Bennett (1).[3] Variations in costs associated with changes in size and production were derived following the method described by Verner and Shurtz (27).

On the basis of the mathematical mine model, it is assumed that labor costs vary proportionately to the 0.4 power of capacity; costs of supplies vary directly with capacity; capital costs for the mill vary proportionately to the 0.7 power of capacity; and mine capital costs vary proportionately to the 0.8 power of capacity. The type of metal to be found along with the gold is unknown, and it was estimated that the milling equipment required to process some other metal would increase the mill capital cost by an average of

---

[1] Originally prepared by Robert L. Adams and John W. Sprague, Division of Mineral Economics, Bureau of Mines, Washington, D.C., October 1967.

[2] Appendix B was initially prepared as a separate Bureau of Mines document for presentation to the Bureau of the Budget.

[3] Underlined numbers in parentheses refer to items in the Bibliography preceding the appendixes.

25 percent for ore with half its value in gold, and 2.5 percent for ore with 0.9 of its value in gold. It was estimated that coproduct or byproduct metals would have little or no effect on the other production costs. With these assumptions, it is possible to estimate the optimum level of production for a deposit of a given size and with a given grade of ore.

The Geological Survey (USGS) provided two sets of estimates, both minimal and probable, of how much gold and other coproduct or byproduct metals they expected could be found in epithermal and Carlin-type deposits; both estimate sets are broken down into four ore grade categories, as shown in table B-1.

While it is more realistic to assume that each target area will contain ore of varying grades, the complexities involved in determining the optimum level of production based on such an assumption suggested another approach. Instead it was assumed that only one of the four grades of ore would be found in any given target area. In this way costs per ton of ore will vary only with production levels rather than with both cost per ton and revenue per ton. With the quantity of gold for each of the four grades of ore in table B-1 considered as one target area, an assumption has been made concerning the size of the deposits which will make up each target area. Each target area will be made up of deposits of 1.4 million ounces, the approximate average deposit size found in the past.

In calculating the optimum level of production and net income for a deposit of this size, a royalty payment of 5 percent of gross value, a 52-percent corporate income tax, and a 15-percent depletion allowance were included.[5] Finally, the assumption was made that a company will not undertake production in a target area unless it is able to earn an investment return of at least 12 percent, which is about the average for all mining. Given that part of the objective of the heavy metal program is reducing the uncertainties in gold exploration and given that there is no uncertainty in prices and markets for the output, it is a reasonable assumption that a 12-percent investment could be realized.

TABLE B-1. - Total gold reserves by grade of ore, million ounces

	Epithermal deposits (ratio of gold to total value 0.5)				Carlin-type deposits (ratio of gold to total value 0.9)			
Ore grade category, oz/ton	0.15	0.11	0.07	0.035	0.27	0.198	0.126	0.063
Minimum..................	1.5	1.7	4.3	13.7	2.7	3.1	7.7	24.7
Probable.................	7.0	8.0	20.0	64.0	12.6	14.4	36.0	115.0

The Economic Analysis

Based on the preceding assumptions, analysis shows that a 1.4-million-ounce-deposit, either epithermal or Carlin-type, would only be economic with present technology if it contained the highest grade of the four grades of ore listed. Both the highest ore grade for Carlin-type and epithermal deposits (27 and 15 ounces of gold per ton, respectively) will provide a gross revenue of $10.50 per ton of ore. (The grades of ore differ because only 0.9 of the

value of Carlin-type ore and 0.5 of the value of epithermal ore is assumed to come from gold.) The optimum level of production of a Carlin-type deposit of this grade of ore would have an annual production of 270,000 ounces for about 5 years. The optimum level of production for an epithermal deposit is 300,000 ounces per year for 4.5 years. Under the minimum USGS estimate of reserves (table B-1) there would be two Carlin-type and one epithermal deposits with present technology. Under the probable estimate of reserves, there will be nine Carlin-type and five epithermal deposits with present technology.

It is estimated that the Bureau of Mines heavy metal research program will bring about technologic improvements which will result in a 25-percent reduction in overall costs incurred in open-pit gold mining. This 25-percent cost reduction will have a twofold effect upon gold production. First, it will increase the optimum level of production for the 0.27 ore in Carlin-type deposits from 270,000 to 540,000 ounces per year, and for the 0.15 ore in epithermal deposits from 300,000 ounces to 600,000 per year. While the total gold to be mined from these two grades of ore will be the same, it will have a higher present value because it will be mined at a time closer to the present. The second effect of cost reduction is that the gold in the next lower grade of ore in both Carlin-type and epithermal deposits will provide a return in investment greater than 12 percent. The optimum level of production for a 1.4-million-ounce-deposit of 0.198 ounce per ton of Carlin-type ore will be 386,000 ounces for 3.5 years. The optimum level of production for an epithermal deposit of 0.11 ounce per ton ore is 440,000 ounces for 3.5 years. Under USGS minimum estimates of reserves there would be two such Carlin-type deposits and one epithermal deposit; under the probable estimates there would be 10 Carlin-type and six epithermal deposits. (See table B-2.) Figure B-1 shows the optimum level of production and the maximum return on investment for both Carlin-type and epithermal deposits that will come from a 1.4-million-ounce deposit at each of the four ore grades. This information is shown for two cases, under present technology and after the introduction of cost reductions induced by Bureau of Mines research. It is estimated that 1976 will be the average year for the estimated deposits to begin production. Table B-3 presents the estimated total annual gold production that will come from new epithermal and Carlin-type deposits.

TABLE B-2. - Estimated annual production per 1.4-million-ounce deposit by grade of ore

Grade of ore, oz/ton	Without Bureau of Mines Research				With Bureau of Mines Research			
	Production, ounces	Minimum life per deposit, years	Number of deposits: Minimum estimate	Number of deposits: Probable estimate	Production, ounces	Minimum life per deposit, years	Number of deposits: Minimum estimate	Number of deposits: Probable estimate
CARLIN-TYPE DEPOSIT								
0.27...	270,000	5	2	9	540,000	2.5	2	9
.198..	-	-	-	-	396,000	3.5	2	10
EPITHERMAL DEPOSIT								
0.15...	300,000	4.5	1	5	600,000	2.5	1	5
.11...	-	-	-	-	440,000	3.5	1	6

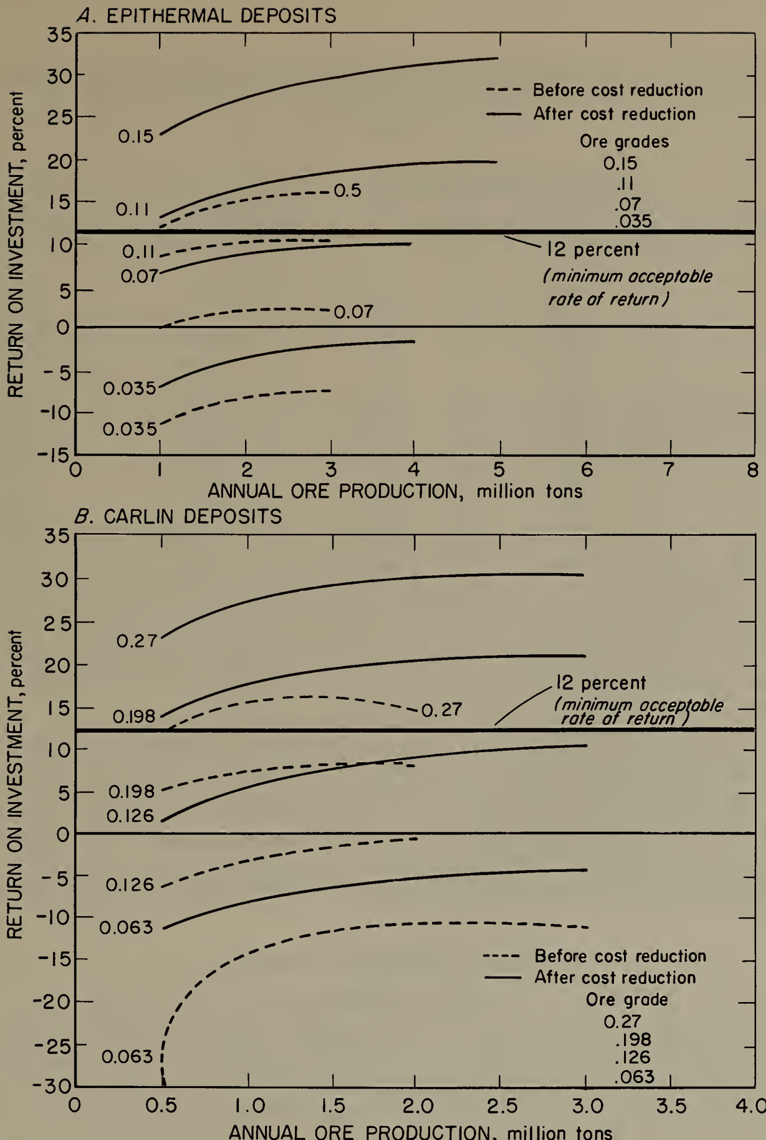


FIGURE B-1. - Estimated Annual Ore Production Before and After 25 Percent Cost Reduction for Carlin-Type and Epithermal Deposits.

TABLE B-3. - Estimated total annual production rate with 1.4 million ounces of original reserves per deposit

(thousand ounces)

Year	Minimum estimate of reserves		Probable estimate of reserves	
	Without cost reduction	With cost reduction	Without cost reduction	With cost reduction
1970..........	0	0	0	0
1971..........	0	440	0	396
1972..........	0	440	270	1,332
1973..........	270	836	540	2,268
1974..........	270	616	1,110	3,776
1975..........	270	936	1,680	4,816
1976..........	570	738	2,250	5,556
1977..........	570	810	2,550	5,776
1978..........	300	540	2,700	5,776
1979..........	300	666	2,370	5,176
1980..........	420	396	2,100	4,136
1981..........	270	396	1,530	2,460
1982..........	270	798	960	1,084
1983..........	270	600	540	198
1984..........	270	300	270	0
1985..........	0	0	0	0

All of the information presented thus far has been based on the assumption that the total reserves in each deposit will be 1.4 million ounces with no more discovered once production begins. (The cost-benefit analysis which follows is also based on this assumption.)

If, however, it is assumed that this is only an original estimate upon which the size of the mill is determined, and that the deposit could actually be larger, the optimum level of production per deposit will remain the same, while the life of each deposit will be extended and the returns increased. Estimates of the added production could have been calculated but, to be conservative, all benefits, costs, and the final internal rates of return assigned to Bureau research were calculated on the basis of the mine lives shown in table B-2.

Project Cost-Benefit Analysis

Industry Acceptance

The first step of the project cost-benefit analysis was to determine which of the grades of gold to be discovered as a result of the project would yield, when developed, a rate of return sufficient to attract private investment capital. The minimim satisfactory rate of return was assumed to be 12 percent. Productivity calculations based on the assumption of present technology, showed grades 0.15 epithermal and 0.27 Carlin-type yielding a rate of return in excess of 12 percent; based on the assumption of 25 percent cost reduction, calculations showed grades 0.11 epithermal and 0.198 Carlin-type

becoming commercial grades. The projected production from deposits of these four grades was then used as the basis for calculating private industry cost and benefits for this project. (Those grades of gold yielding less than a 12-percent rate of return were not considered further.)

Probability of Success Allowance

A 100-percent probability of success was assumed for all aspects of the project, due to time constraints.

Estimated Government Program Costs

The estimated costs of the Government program for Carlin-type and epithermal deposits are shown below:

Agency	FY 1967	FY 1968	FY 1969	FY 1970	FY 1971
USGS..............	$1,600,000	$1,975,000	$1,975,000	$1,863,000	$1,738,000
Bureau of Mines...	1,440,000	2,065,000	2,200,000	6,480,000	6,100,000

Internal Rate of Return and Present Values

Net benefits were calculated, based on the optimum production level under each of the four different assumptions as to size of total reserves. The net benefits under each assumption were then discounted over the applicable time horizon (1966-80 with present technology; 1966-79 with a 25-percent cost reduction with future technology) in order to obtain the internal rates of return. Tables B-4 and B-5, showing the cost and benefit streams under each of the four assumptions, are presented at the end of this section.

The rate of return for each assumption is given below:

Technology level	Reserve-size estimate	Internal rate of return, percent
Present............	Minimum...............	11
Do...............	Probable..............	21
Future[1]	Minimum...............	12
Do.[1]	Probable..............	21

[1]It is assumed that future technology will permit a 25-percent cost reduction.

These rates of return cannot be used as a sole criterion of project worth. As ratios they only show relative benefits, not absolute benefits. Hence, while the rates of return are similar with or without the cost reduction expected from Bureau of Mines research, the absolute levels of benefits (that is, increased gold production) are much higher with the cost reductions. These differences are indicated in the following table, which presents the present value of net project benefits with and without the cost reduction.

Technology level	Reserve-size estimate	Net benefits, present value[1]
Present..............	Minimum..............	$4,507,300
Do..................	Probable.............	82,604,061
Future[2]...............	Minimum..............	19,692,584
Do.[2]................	Probable.............	190,766,970

[1] Present value obtained as follows: (1) Industry benefits and costs discounted at 12 percent over applicable time horizon, (2) Government costs discounted at 6 percent over applicable time horizon, and (3) discounted Government costs subtracted from discounted industry net benefits to obtain present value figures.

[2] It is assumed that future technology will permit a 25-percent cost reduction.

As shown, the present value of project net benefits under the minimum assumption is increased approximately $15 million with the achievement of a 25-percent cost reduction; under the probable assumption, a 25-percent cost reduction increases the present value by over $100 million.

All rates of return and present value figures were calculated assuming a net benefit stream based on estimated reserves with a productive life as shown in table B-2. As noted, historically it has been the case that as known reserves are committed to production, additional reserves are discovered and project life extended. To the extent that this occurs, the rate of return and present value figure under all four alternatives would tend to increase, limited primarily by the time horizon and the applicable discount rate.

Another potential source of project benefits would be the increased gold production from presently inoperative mines which would be reopened because of the 25-percent cost reduction.

No sensitivity analysis was employed on the 25-percent cost reduction assumption due to time constraints. However, the rate of return on both cost reduction alternatives was 20 percent or better. Since these rates of return provide a considerable margin of safety over the 12-percent minimum rate of return, it appears that 25 percent is not the minimum cost reduction necessary to bring in additional gold production. Rather, it appears that a cost reduction of something less than 25 percent would bring in sufficient new production to maintain a favorable cost-benefit relationship for these project alternatives.

Project Optimization

No attempt was made to optimize project expenditure levels because of time constraints. A single level of funding was assumed (and therefore only a single research alternative) for both USGS and the Bureau of Mines. As a result, this study does not represent a comprehensive cost-benefit analysis. Rather, it shows the direct benefits of various increases in the level of gold production, as developed within a framework of assumptions based on information largely provided by USGS and the Bureau of Mines Office of Minerals Research.

No attempt was made to evaluate such factors as (1) possible benefits from a reduction in industry accident rates due to a trade-off between open-pit and underground mining of gold; (2) environmental implications, such as the effects of the significant amounts of solid waste expected to occur as a byproduct of the levels of production envisioned in this project; and (3) other potential social effects.

TABLE B-4. - Project costs and benefits under present technology[1]

Year	Minimum estimate of reserves			Probable estimate of reserves		
	Benefits	Capital costs	Geological survey costs	Benefits	Capital costs	Geological survey costs
	Internal rate of return, 10.7 percent			Internal rate of return, 21.2 percent		
1966	-	-	$800,000	-	-	$800,000
1967	-	-	1,787,500	-	-	1,787,500
1968	-	-	1,975,000	-	-	1,975,000
1969	-	-	1,919,000	-	-	1,919,000
1970	-	-	1,800,500	-	-	1,800,500
1971	-	-	869,000	-	-	869,000
1972	-	-	-	-	-	-
1973	-	-	-	-	-	-
1974	-	$29,530,988	-	-	$120,839,851	-
1975	-	29,530,988	-	-	120,839,851	-
1976	$22,473,379	-	-	$107,086,135	-	-
1977	22,473,379	-	-	107,086,135	-	-
1978	22,473,379	-	-	107,086,135	-	-
1979	22,473,379	-	-	107,086,135	-	-
1980	16,517,450	-	-	77,306,488	-	-

[1] Industry capital costs are assumed to start in 1974 and run for 2 years, and gold production is assumed to start in 1976. Selecting an average year for these 2 figures does not in any way affect the calculation of the internal rate of return. The benefits in each year equal net profits plus amortization.

TABLE B-5. - Project costs and benefits under future technology allowing a 25-percent cost reduction

Year	Minimum estimate of reserves					Probable estimate of reserves				
	Benefits	Capital costs	Minerals research costs	Geological survey costs	Total Government costs	Benefits	Capital costs	Minerals research costs	Geological survey costs	Total Government costs
	Internal rate of return, 11.8 percent					Internal rate of return, 20.9 percent				
1966	-	-	$720,000	$800,000	$1,520,000	-	-	$720,000	$800,000	$1,520,000
1967	-	-	1,752,500	1,787,500	3,540,000	-	-	1,752,500	1,787,500	3,540,000
1968	-	-	2,132,500	1,975,000	4,107,500	-	-	2,132,500	1,975,000	4,107,500
1969	-	-	4,340,000	1,919,000	6,259,000	-	-	4,340,000	1,919,000	6,259,000
1970	-	-	6,290,000	1,800,500	8,090,500	-	-	6,290,000	1,800,000	8,090,500
1971	-	-	3,050,000	869,000	3,919,000	-	-	3,050,000	869,000	3,919,000
1972	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-
1974	-	$72,048,027	-	-	-	-	$369,034,839	-	-	-
1975	-	72,048,027	-	-	-	-	369,034,839	-	-	-
1976	$88,051,699	-	-	-	-	$446,287,538	-	-	-	-
1977	88,051,699	-	-	-	-	446,287,538	-	-	-	-
1978	62,270,996	-	-	-	-	323,810,079	-	-	-	-
1979	18,245,146	-	-	-	-	100,666,310	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-